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Arizona Corporation Commission
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BEFORE THE ARIZONA CORPORATION COMMISSION

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CARL J. KUNASEK
Chairman
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Commissioner
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Commissioner

IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. U-0000-94-165 **TUCSON ELECTRIC POWER COMPANY'S MOTION FOR RECONSIDERATION AND REQUEST FOR STAY**

Tucson Electric Power Company ("TEP" or "Company"), pursuant to A.R.S. § 40-253 and A.A.C. R14-3-111, hereby moves the Arizona Corporation Commission ("Commission") to:

1) Reconsider Decision No. 59943 dated December 26, 1996 ("Decision") which adopted Proposed Rules on Retail Electric Competition (R14-2-1601, *et seq.*) ("Rules"); and

2) Order a stay of the enforcement of the Rules pending the amendment of the Rules consistent with TEP's comments (as set forth in Exhibit B attached hereto) or the repeal of the Rules by the Commission or the Courts, because the Rules will otherwise be effective notwithstanding a reconsideration or appeal.[1]

This requested relief is in the best interests of the public and is fair and equitable to all concerned parties—consumers, utilities and the Commission—because it provides a meaningful opportunity to review the Rules, the manner in which they were adopted and their impact without unnecessarily subjecting the state of Arizona to their unwanted consequences. Further, in order to achieve the Commission's stated objective of moving the electric industry to competition, this relief will open a window of opportunity for the parties to jointly develop the legal and technical details that are lacking in the regulatory "framework" that is now in place. Such a process, which has been successfully conducted in other jurisdictions, but was not followed in Arizona, will protect the

[1] By requesting a stay of the enforcement of the Rules, TEP does not waive any right to appeal the Rules as adopted or as may be subsequently amended, the manner in which the Rules were adopted or as may be subsequently amended, or the Decisions of the Commission issued in connection with the Rules.

welfare of the consumer, the financial stability of the "Affected Utilities" and meet the Commission's stated objective of bringing retail competition to Arizona in a timely manner.

TEP believes that by filing this motion and request for a stay, the Commission will have one more opportunity to examine *at least* the following areas of concern with the Rules, prior to their enforcement:

a) System Reliability. To ensure that all citizens of Arizona (and the Southwest) continue to receive safe, reliable and economic electric service.

b) Economic Impact to the State. To quantify, and if possible minimize, the cost of potential lost revenues and taxes to the state and its political subdivisions.

c) Stranded Cost. To recognize changes to the "Regulatory Compact" and related financial consequences to the "Affected Utilities."

d) Level Playing Field. To thoroughly study and implement retail competition in a fair and equitable manner, which may require legislative action in light of issues such as "Salt River Project reciprocity" and preference power.

e) Legal Issues. To identify and correct through, Commission, judicial, legislative and constitutional means, the various legal problems posed by the Rules under existing Arizona law.

f) Judicial Review. To identify and remedy all procedural and substantive defects in the Rules and the manner in which they were adopted in order to avoid costly and time consuming litigation.[2]

As set forth more fully in the supporting Proposed Form of Order (attached hereto as Exhibit A and incorporated herein) and Memorandum of Points and Authorities (attached hereto as Exhibit B and incorporated herein), TEP respectfully requests the Commission to issue an order as follows:

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[2] One blatant example of this is the amendment of AAC R14-2-1611. In the proposed rules circulated for public comment, an entity such as SRP could not participate unless Affected Utilities consented in writing, thereby giving Affected Utilities a "right" in this process. The amendments to the Rules adopted at the Special Open Meeting took that "right" away from the Affected Utilities and changed the process in which SRP could participate. This was a substantive change that should have resulted in a re-noticing of the Rules under the APA.

1) Granting TEP's Motion for Reconsideration of the Decision;

2) Granting TEP's Request for a Stay of the Rules;

3) Establishing a schedule for evidentiary hearings to remedy all of the procedural and substantive deficiencies in the Rules as described more fully in Exhibit B; and

4) Concluding that pursuant to the Arizona Administrative Procedures Act ("APA"), a notice of proposed rulemaking to either amend or repeal and replace the Rules should be issued as a result of the evidentiary hearings to remedy all of the procedural and substantive deficiencies in the Rules as described more fully in Exhibit B.

RESPECTFULLY SUBMITTED this 10th day of January, 1997.

TUCSON ELECTRIC POWER COMPANY

By: ______________________

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CERTIFICATE OF SERVICE

Original and ten copies of the foregoing filed this 10th day of January, 1997, with:

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By: Sandra Waters
Sandra Waters
Legal Secretary

EXHIBIT A

BEFORE THE ARIZONA CORPORATION COMMISSION

CARL J. KUNASEK
Chairman
JIM IRVIN
Commissioner
RENZ D. JENNINGS
Commissioner

IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. U-0000-94-165 DECISION NO. ____________ ORDER

Open Meeting
January ___, 1997
Phoenix, Arizona

BY THE COMMISSION:

FINDINGS OF FACT

1 On December 26, 1996, the Arizona Corporation Commission ("Commission") issued Decision No. 59943 ("Decision") which adopted Proposed Rules on electric Competition (R14-2-16-1 through R14-2-1616 ("Rules")

2. On December 26, 1996, pursuant to the Decision, the Rules were forwarded to the Secretary of State and became effective.

3. On January 10, 1997, Tucson Electric Power Company ("TEP"), an Arizona corporation and an "Affected Utility" under the Rules, filed a Motion for Reconsideration and Request for Stay which incorporated an accompanying Memorandum of Points and Authorities ("Motion").

4. The Motion requested the Commission to reconsider the Decision and stay the enforcement of the Rules pending the amendment of the Rules (consistent with TEP's comments as set forth in Exhibit B to the Motion) or the repeal of the Rules by the Commission or the Courts.

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5. The Motion indicated that at least the following areas of concern were not adequately addressed by the Rules, including procedural and substantive defects contained in the Rules under the Administrative Procedures Act ("APA"):

A. System Reliability;

B. Economic Impact to the State;

C. Stranded Cost;

D. Level Playing; and

E. Legal Issues.

6. Given the Commission's intention of amending the Rules to address the issues raised by TEP, as well as to avoid the potentially unnecessary and costly appeal of the Rules, TEP's Motion is in the public interest and should be granted.

CONCLUSION OF LAW

1. The Commission has jurisdiction and authority over the Rules pursuant to the Arizona Constitution, Article XV and the Arizona Revised Statutes.

2. The Commission has jurisdiction to consider TEP's Motion pursuant to A.R.S. § 40-253 and A.A.C. R14-2-111.

3. The granting of the Motion is in the public interest and should be granted.

ORDER

IT IS THEREFORE ORDERED that the Commission shall hereby reconsider Decision No. 59943.

IT IS FURTHER ORDERED that the enforcement of A.A.C. R14-2-1601 through R14-2-1616 is hereby stayed pending further order of the Commission.

IT IS FURTHER ORDERED that within 10 days from the date of this Decision, the Utilities Division and the Hearing Division shall establish a procedural schedule to conduct workshops and evidentiary hearing to examine the issues raised in TEP's Motion.

IT IS FURTHER ORDERED that following the workshops and evidentiary hearings, the Utilities Division shall initiate the process pursuant to the Administrative Procedures Act to amend (or if necessary repeal the Rules and adopt new rules) consistent with the findings of the evidentiary hearings.

. . .

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION

CHAIRMAN	COMMISSIONER	COMMISSIONER

IN WITNESS WHEREOF, I, JAMES MATTHEWS, Executive Secretary of the Arizona Corporation Commission, have hereunto, set my hand and caused the official seal of this Commission to be affixed at the Capitol, in the City of Phoenix, this ______ day of ______________, 1997.

____

JAMES MATTHEWS
Executive Secretary

DISSENT ____________________________

EXHIBIT B

BEFORE THE ARIZONA CORPORATION COMMISSION

CARL J. KUNASEK
Chairman
JIM IRVIN
Commissioner
RENZ D. JENNINGS
Commissioner

IN THE MATTER OF THE COMPETITION IN THE PROVISION OF ELECTRIC SERVICES THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. U-0000-94-165 **TUCSON ELECTRIC POWER COMPANY'S MOTION FOR RECONSIDERATION AND REQUEST FOR STAY**

MEMORANDUM OF POINTS AND AUTHORITIES

On Behalf of

TUCSON ELECTRIC POWER COMPANY

January 10, 1997

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I. INTRODUCTION

A. Introduction

While TEP believes that initially rules are necessary to make competition a reality in Arizona, the Commission has not taken sufficient time to develop these Rules and to determine their potential impact to the State, Arizona utilities, consumers and shareholders. Rather than merely criticize the Commission's efforts or the Rules, TEP has submitted comments that explain its position and proposed an alternative for the adoption of rules. Unfortunately, TEP's comments were ignored by the Commission and the Rules remain seriously flawed. TEP's Motion for Reconsideration is another non-judicial attempt to request the Commission to implement Rules that will fairly and legally usher retail electric competition into Arizona.

B. Procedural History

On May 20, 1994, the Commission Staff opened Docket No. U-000-94-165, *In the Matter of the Competition in the Provision of Electric Services Throughout the State of Arizona* ("Docket"), in order to study and consider electric industry restructuring for the State of Arizona. Since that time, TEP has been an active participant in that Docket. Following the introductory workshop that was held on September 7, 1994, a series of working group and task force meetings were held to identify the major restructuring options, implementation of the options and advantages and disadvantages of the options to the various interests represented. Task force meetings included a Legal Task Force which was established to identify the legal issues the Commission would be required to address prior to implementation of electric industry restructuring in the State. Those issues were summarized in the *Report of the Working Group on Retail Electric Competition*, dated October 5, 1995.

On February 22, 1996, Staff issued a *Request for Comments on Electric Industry Restructuring* which asked the participants to respond to 19 broad questions regarding electric industry restructuring. On June 28, 1996, more than 30 parties filed hundreds of pages of comments. Approximately three weeks later, Staff filed a summary of those comments and scheduled a one-day workshop to be held on August 12, 1996 to consider elements of two composite rules. Approximately 130 people attended that workshop where issues that easily required days of discussion were given (in some cases) minutes of attention. One week later, Staff issued a report summarizing the workshop and on August 28, 1996, issued the draft of definitive rules, providing interested parties only 10 business days to comment. Comments to the draft rule were submitted on

September 12, 1996 and Staff conducted a one day workshop on September 18, 1996 to discuss the comments. Less than two weeks later, Staff submitted the Rules to the Commission. The Commission authorized that a Notice of Proposed Rulemaking be forwarded to the Secretary of State on October 9, 1996. By Procedural Order dated October 11, 1996, the Commission *requested* that comments on the Rules be filed by November 8, 1996 and that any rebuttal comments be filed by November 27, 1996, despite the fact that the record in this matter was open until December 4, 1996. TEP submitted written comments (including an alternative proposal) on November 8 and December 4, 1996. On December 13, 1996, Staff (as opposed to the Hearing Division), the very party that proposed the Rules, issued a Proposed Order to adopt the Rules. TEP filed its Exception to the Proposed Order on December 19, 1996. The Commission adopted the Rules at a Special Open Meeting held on December 23, 1996 (with the inclusion of substantive amendments) and the Decision was issued on December 26, 1996. The Rules became effective upon filing with the Secretary of State on December 26, 1996.

C. The Alternate Proposal Recommended by TEP in its Comments

In an attempt to get this rulemaking proceeding on the right track and still meet the deadlines in the Rules, TEP in its comments, proposed that the Commission, rather than formally adopting the Rules, issue a Statement of Policy ("Policy") that would contain all of the substantive provisions of the Rules including the various time frames and deadlines stated therein. The Policy could require that all workshops and inquiries be held in the first half of 1997 with definitive rules proposed in the third quarter of 1997 for adoption before the end of that year. Tariffs could be filed by the end of the first quarter of 1998 and competition could commence in 1999 as currently contemplated.

TEP indicated its belief that this process was a more reasonable and comprehensive approach than implementing the Rules (when all who are affected thereby realized that it will have to be changed later). It had the features of: (i) putting the utilities and public on notice that the Commission will implement competition; (ii) permitting Staff and the interested parties to attempt resolutions of major issues of concern; (iii) maintaining the original deadlines established by the Commission in the Rules; and (iv) avoiding the delay in implementation of the Rules occasioned by litigation over their terms and the manner in which they were adopted. In essence TEP requested that the Commission reject the Rules on December 23, 1996, issue the Policy and begin workshops as soon as practicable. This proposal was rejected by the Commission.

D. <u>The FERC Proceeding</u>

The federal proceeding to facilitate competitive wholesale electric power markets was formally begun with the issuance on June 29, 1994, of the Federal Energy Regulatory Commission's ("FERC") Notice of Proposed Rulemaking, in Docket No. RM94-7-000, *Recovery of Stranded Cost by Public Utilities and Transmitting Utilities* ("Stranded Cost NOPR"). Many parties including the Commission filed comments in the Stranded Cost NOPR proceeding pursuant to FERC Regulations. While the Stranded Cost NOPR raised issues related to the recovery of utility costs that would be "stranded" as a result of a shift to a more competitive wholesale power market, that proceeding did not address, *per se*, open access principles. On March 29, 1995, FERC issued its *Notice of Proposed Rulemaking and Supplemental Notice of Proposed Rulemaking*, in Docket Nos. RM95-8-000 and RM94-7-001, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; and Recovery of Stranded Cost by Public Utilities and Transmitting Utilities* ("Open Access NOPR"), IV FERC STATS. & REGS. Paragraph 32,514 (1995). FERC's Open Access NOPR proposed to apply the proposed access principles to public utilities that own and/or control facilities used for the transmission of electric energy in interstate commerce. FERC consolidated the issues raised in the Stranded Cost NOPR into the Open Access NOPR. The two proceedings have continued as one since March 29, 1995.

Pursuant to its regulations, FERC requested that all interested parties file comments on the NOPR on or before August 4, 1995. Over 350 parties, including the Commission, individually and as members of joint filings, filed over 12,000 pages of initial comments in the Open Access NOPR. Approximately 150 parties filed nearly 4,000 pages of reply comments. During several days of technical conferences held in October 1995, representatives of all aspects of the electric industry presented views on the Open Access NOPR to FERC. FERC issued its Final Rules in Docket Nos. RM95-8-000 and RM94-7-001 ("Order 888") on April 24, 1996, more than one year after the issuance of its Open Access NOPR. Requests for rehearing of Order 888 were filed on or before FERC's deadline of May 24, 1996 and remain pending.

Even given this intensive schedule and allotted time, FERC was forced to delay the implementation of Order 889, the Open Access Same-Time Information System ("OASIS"). The OASIS is the computer system behind the concept of equal access to transmission information. The technical requirements proved to be greater than originally anticipated and utilities could not install and train employees in time for the original implementation requirement. The original date for OASIS implementation was November 1, 1996, but FERC moved this date to January 3, 1997 to give utilities more time to work out the technical requirements and to hire and train staff.

E. The California Proceeding

In April 1992, the California Public Utilities Commission ("CPUC") initiated a comprehensive review of current and future trends in the electric industry. This process produced a rulemaking proceeding (R.94-04-031) concerning restructuring of California's electric services industry and reforming regulation, which was issued on April 20, 1994 ("Rulemaking"). The Rulemaking was issued for extensive public comment and solicited comprehensive alternatives to the vision described in that document.

Since April, 1992, the CPUC has conducted public hearings throughout California. A week of evidentiary hearings on uneconomic assets has been conducted. Other regulatory bodies in western North America, federal agencies and legislators have been consulted about cooperative solutions to jurisdictional issues. A working group provided a report on sustainability of public purpose programs and numerous parties filed briefs on legal issues. On May 24, 1995, the Commission issued majority and minority policy preference statements.

On December 20, 1995, the Commission approved its proposed policy decision and in its press release, the CPUC states, "Because restructuring of California's electric services industry has widespread impact and the market structure requires the participation and oversight of the FERC, the CPUC will work over the next ***100 days*** (emphasis added) to build a California Consensus involving the Legislature, the Governor, public and municipal utilities and customers. This Consensus would then be placed before the FERC so that in a spirit of 'cooperative federalism' the CPUC and FERC could together implement the new market structure by January 1, 1998." Since December, 1995 the CPUC established seven working groups: Direct Access, Energy Efficiency and Demand-Side Management, Low-Income, Ratesetting, Renewable Energy, Research, Demonstration and Development and Western Power Exchange. The groups have been meeting at least once a month since the beginning of 1996 to resolve specific issues relating to the 1998 implementation deadline and each group reports meeting results and issues on the Internet.

Just recently the California Legislature passed, and Governor Wilson, signed H.B. 1890, a landmark restructuring bill which generally endorses major policies adopted by the CPUC. This dictates some details of implementation, but leaves most for the CPUC to determine at a future date. One major aspect left unresolved is how to accomplish direct access competition for customers, which is the subject for the Direct Access Working Group mentioned above. An important difference from the CPUC order, however, is that the legislation establishes a mechanism in which bonds will be used to pay off at least a portion of utilities' stranded assets so that residential and commercial ratepayers will receive a 10 percent rate cut by 1998 and work toward the goal of an additional 10 percent cut in 2002. The California legislation also provides for renewables and certain other social-policy programs during a four-year transition to a competitive marketplace through a non-bypassable charge of $540 million imposed on customers of investor-owned utilities and a proportionate non-bypassable charge imposed on customers of muncipally-owned utilities.

F. Conclusions

The total time between the initial 1992 review in California and final implementation of its rules is five years and eight months. Although TEP is not suggesting the Commission duplicate the California process, it illustrates the need for an appropriate time commitment for interested parties to work out details and legislative coordination to address these important issues. In stark contrast to the California processes, the Arizona proceedings did not give interested parties time to debate important topics or allow complex issues to be resolved. Further, there was no attempt to build a consensus. Instead, the Rules take a "we'll figure this out later" approach to the major issues without regard to the inevitable implications. TEP believes that it is important to allow time to fully develop a plan that will work in Arizona and to avoid implementing an ambiguous, less than adequate plan that will only cause delays because important issues were left for later.

Given the fact that as of June 28, 1996, the process in Arizona was at a point where participants were still providing comments on broad topics and issues and were given four months to do this, it is not fair or appropriate that less than six months later and with approximately 14 pages of text, that the Commission was at a point that it was ready to adopt definitive Rules. These Rules will dramatically affect a multi-billion dollar industry and change a relationship between utilities, shareholders, regulators and customers that has existed for more than 80 years. Further, because of this pressure to finalize the Rules on an expedited basis, there are serious structural, legal, financial and operational problems that have not as yet been addressed by Staff (*see* discussion below.) Although TEP strongly supports competition, the Company believes that it is essential that the

Commission ultimately adopt Rules that provide more answers than questions and is consistent and equitable in their application. Consequently, TEP believes that the granting of the requested relief set forth in its Motion for Reconsideration and Request for Stay is appropriate and in the public interest.

II. STRANDED COST

A. Introduction

Stranded Cost represents the most significant issue facing TEP, the Commission and the other parties to this Electric Industry Restructuring Docket. The transition from a regulatory model based on one vertically-integrated utility providing full electric service under a single bundled rate in a specific geographic area, to a direct access market in which customers can readily choose any energy supplier will undoubtedly require recognition of significant transition costs. Consistent with the assurances and obligations that have existed under the traditional Regulatory Compact, a mechanism must be created before the industry transition begins, such that a reasonable opportunity is provided for the full recovery of Stranded Cost prior to completion of the evolution to retail competition. In order to achieve a smooth and efficient transition to a competitive electric marketplace, the Commission must establish a framework which ensures the full recovery of Stranded Cost and provides price stability for consumers. The only effective method of achieving this transition is for the Commission to find that all prudent, verifiable and legitimate Stranded Cost is recoverable, to develop a general set of guidelines to define Stranded Cost and appropriate recovery mechanism and to authorize recovery of Stranded Cost from all customers that stand to benefit from a competitive electric industry.

Following is a discussion of: (i) the traditional Regulatory Compact and why recovery of Stranded Cost is an essential element of that compact; (ii) a recommended methodology for quantifying and recovering Stranded Cost; (iii) identification of the key accounting and financial implications associated with Stranded Cost; and (iv) other relevant information that should be considered by the Commission in addressing this most important issue. Following that discussion are TEP's specific comments with respect to R14-2-1607 of the Rules, "Recovery of Stranded Cost of Affected Utilities."

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B. Background

The traditional Regulatory Compact between public utilities, the customers they serve and the state is unquestionably clear. It is an agreement, sanctioned by the state, granting the exclusive right to serve the public interest in a specific geographic area. In return, utilities assumed two obligations **not imposed** on other competitive entities: (i) the obligation to serve; and (ii) the regulation of prices and earnings. The obligation to serve carries an obligation to invest in and maintain the plant, or enter into contracts to assure sufficient supply to meet all customer demands for utility service. Virtually every major investment decision utilities have made to date has been in recognition of, and reliance upon, this Regulatory Compact.

Under the Regulatory Compact, utilities were provided some assurance as to the limits of their business risk, which correspondingly resulted in limited rates of return implicit in the prices they were allowed to charge for service provided. Utility investments in assets and obligations were incurred in good faith and in expectation that a reasonable opportunity would be provided to achieve the designated returns. With the emergence of competition, some of the embedded costs traditionally recovered through regulated rates will be totally or partially unrecoverable. The difference between expected future revenues under regulation and the expected revenues that would likely occur under total or partial competition constitute "Stranded Cost." Stranded Cost may take a variety of forms, including: (i) assets owned, leased or purchased by contract; (ii) services, materials and supplies owned or contracted; (iii) unrecorded liabilities (*i.e.*, fuel and purchased power contracts); (iv) operating and capital costs; (v) regulatory assets (costs for which recovery has been deferred for ratemaking purposes over longer periods than would be found in a competitive market); and (vi) amounts not yet recovered in the regulatory process (*i.e.*, accrued post-employment healthcare costs).

Similar electric industry restructuring proceedings around the nation have already spent considerable time and effort addressing the issue of Stranded Cost and have determined that full recovery thereof is an essential requirement for an efficient, equitable transition to competition. In its Order 888 promoting wholesale competition through open access transmission service, the FERC clearly recognized that full recovery of stranded wholesale costs is not only a legal obligation of regulators, but also is necessary to achieve an efficient transition to competition. Other states considering retail competition have also recognized the potential for Stranded Cost and the need for their full recovery. Utility investors are entitled to a reasonable opportunity to recover the capital they provided in good faith. Clearly, the rates of return granted under the traditional regulatory paradigm never contemplated this significantly increased business risk.

C. Definition of Stranded Cost

A key consideration in addressing the issue of Stranded Cost is just how it is defined. Stranded Cost should not be viewed simply in terms of categories of costs, but rather as revenue requirements that a utility has lost the opportunity to collect as a result of existing customers obtaining power from alternative sources. In connection therewith, TEP believes the following to be an appropriate definition of Stranded Cost:

> An aggregation of costs (the prudence of which has already been established) incurred for, or in anticipation of, the provision of service under a regulatory framework, that are likely unrecoverable in a competitive market for power with prices based on marginal cost.

The above definition is similar to that appearing in R14-2-1601, No. 8 of the Commission's Rules; however, several key distinctions are noteworthy.

First, the Commission's definition refers to "the value of all the prudent jurisdictional assets and obligations. . ." It is unclear whether such definition would result in a reconsideration of the prudence of past investment decisions. TEP strongly believes that the consideration of Stranded Cost should not include ex-post prudence reviews of costs that are already being recovered in the utilities' rates. The fact that recovery is already being allowed is sufficient assurance of prudence. TEP has already been required by the Commission to write off $564 million, including $428 million of the cost of its Springerville and Irvington generating facilities. The utilities should not have to revisit prudence issues, simply because some costs now recovered in rates would, in the future, be included in a Stranded Cost charge.

A second concern of TEP with respect to the Commission's proposed definition of Stranded Cost is that it tends to focus on the difference in values of assets and obligations under traditional regulation as compared with their values after the introduction of competition. It is unclear what specific assets and obligations are included and whether the definition is limited to balance sheet accounts. Stranded Cost is not limited to generation assets. Utilities have considerable investments in regulatory assets that may become strandable under competition. In addition, generation-related operating expenses (*i.e.*, fuel expenses, including mine reclamation costs) may also be considered as a Strandable Cost. Moreover, some Strandable Costs are not presently reflected in the Company's financial statements, such as the $81 million relating to the Springerville excess capacity deferrals and $19 million for employees' post-employment healthcare relating to services already provided. Equally unclear in the definition is the basis by which "market value" will be established.

One possible method to calculate Stranded Cost is the difference between future revenues under regulation and competition scenarios, rather than differences in market values of utility assets. This eliminates the need for an asset-by-asset determination, and more correctly recognizes that utilities have made multiple investment decisions under the Regulatory Compact with the expectation of revenue streams from customers to cover the costs of such investments. Moreover, in a direct access power supply market, TEP will continue to serve customers using a portfolio of resources; accordingly, Stranded Cost should be considered on a portfolio basis.

D. <u>Quantifying Stranded Cost</u>

Any method of attempting to quantify Stranded Cost is necessarily speculative and highly uncertain because it requires identification of all relevant resources (both recorded and unrecorded) and offsets, customer demand and predictions of the market clearing price for power over long periods of time. As an example, factors affecting the market clearing price for power (clearly the most critical variable in quantifying Stranded Cost) include: customer demand, market structure, generation and transmission capacity availability, generation fuel mix and costs, interest rates and inflation, developments in technology and new laws and regulations.

A method that would accomplish this quantification would be to quantify stranded assets as the net present value of future annual differences in revenues under a continuation of regulation, versus the amounts likely to be realized after the introduction of competition, using an appropriate discount rate. In general, the resulting amount reflects the difference between the utility's embedded generations costs and the market's marginal costs for supplying power, plus the generation-related portion of the utility's regulatory assets, both recorded and unrecorded. Such method effectively recognizes both above-market and below-market assets.

A specific time period over which Stranded Cost should be computed by every utility cannot, and should not, be ordered. Companies have different assets with different investment and cost recovery horizons. A significant portion of the investments implicit in Stranded Cost is very long-term. Generating assets, for example, have life expectancies in excess of thirty years. Any attempt to arbitrarily set a Stranded Cost calculation time period for all assets together is inappropriate and will likely lead to significant under recovery. Costs were specifically incurred to serve customers over an extended period of time with a reasonable expectation of a fair opportunity for full recovery. Proper quantification of Stranded Cost should reflect the remaining life expectancy of the underlying assets and deferred costs.

E. Stranded Cost Recovery Mechanism

In developing an appropriate Stranded Cost mechanism, TEP recommends that the Commission consider the following objectives:

1) The mechanism should promote economic efficiency and the evolution of competition.

2) Any Stranded Cost recovery mechanism must be fair to stockholders and equitable toward all for whom the underlying costs were intended to benefit, including those that leave the system.

3) Stranded Cost should be recovered in its entirety within a reasonably short time period.

4) The recovery burden should not significantly expand the existing administrative burdens of the Commission or affected utilities.

5) The mechanism should be sufficiently flexible to incorporate changes in assumptions or unanticipated events in the process of transitioning to retail competition.

6) The relevant charge should be simple and understandable to customers and not impede their choice of power supply or other competitive services.

A variety of Stranded Cost recovery mechanisms are available, including entry fees imposed on competing sellers, exit fees on departing customers and access charges on all end users based on energy consumption. TEP believes that the most efficient and effective means of recovering Stranded Cost is through a non-bypassable "wires charge" paid by every customer interconnected to the TEP distribution system, whether power is supplied by this Company or an alternative supplier. The intent is to spread the costs of transition over a broad base of customers that have access to the benefits of a more competitive environment. Such a charge would appear as an explicitly detailed separate line item on customer bills. However, it should be easy to administer and easy for customers to understand. This approach is consistent with the manner in which retail electric customers are aggregated in the Company's system-wide planning process. Moreover, this approach not only recognizes the societal benefits to be achieved from the transition to a more competitive electric industry, but also reflects past precedents set when similar considerations were made for recovering Stranded Cost in the natural gas and telephone industries.

TEP believes that the imposition of a system-wide wires access charge as described above should afford the Company a reasonable opportunity to fully recover its Stranded Cost. The possibility does exist, however, that some customers may attempt to avoid the charges by leaving the system or through self-generation. For any customers opting to self-generate, it is likely they will purchase back-up service from their host utility. They could be allocated a share of Stranded Cost as a component of the standby service charge. Finally, new consumers connecting to TEP's distribution system should pick up their fair share of transition costs in the same manner as if they had been served all along. Otherwise there may be too great an incentive for customers to seek bypass by appearing as if they are "new" customers.

The starting point for developing a Stranded Cost charge is the present value of Stranded Cost at the beginning of the transition period, computed in the manner previously described. Such amounts should then be amortized as an annuity based on the same discount rate over that period to arrive at an annual Stranded Cost recovery requirement. TEP believes that the annual requirement should be allocated to customer groups in the manner in which the related costs underlying current rates have been allocated, and then collected from customers in the form of an energy charge based upon their actual usage or a fixed monthly customer charge. The Commission should not revisit the cost allocation methodologies currently used to assign costs to the different customer rate classes, but such factors should be periodically revisited to identify changes in customer usage characteristics and to ensure that there is no cross-subsidization between customer classes. In addition, the customer charges could be periodically revised to reflect changes in sales forecasts and estimates of the market clearing price for power.

F. <u>Accounting and Financial Implications</u>

In establishing rules for quantifying and recovering Stranded Cost, the Commission needs to consider the potential consequences of ignoring the rights and obligations of all parties implicit in current rates established under the Regulatory Compact. Less than full recovery of Stranded Cost will likely have significant accounting and financial implications.

As a rate regulated entity, TEP prepares its public financial statements according to Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* ("SFAS No. 71"). The underlying premise of SFAS No. 71 is that regulated enterprises should account for the economic effects that result from the cause-and-effect relationship of costs and revenues in the rate-regulated environment. SFAS No. 71 defines what constitutes a regulated entity and contains standards of accounting for the effects of regulation. One such standard addresses the method by which a regulator can create an asset by deferring for future recovery, a current cost that would otherwise be charged to expense. For that to occur, both of the following criteria must be met:

1) It is probable that future revenue in an amount at least equal to the capital cost will result from inclusion of that cost in rates.

2) Based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs.

As long as the above criteria are met, assets may continue to be reflected in a utility's books and financial statements. As soon as either of the above is not met, the corresponding asset must be written off. To illustrate the extent to which regulatory assets impact the financial reporting by a public utility, as of June 30, 1996, TEP's balance sheet included nearly $257 million in deferred regulatory assets.

As competition has surfaced in the utility industry, the ability of regulators to create assets by deferring costs to the future has become increasingly suspect. Accordingly, additional accounting standards have been issued by the FASB to address emerging concerns over accounting by regulated entities. These standards include SFAS No. 90, *Regulated Enterprises-Accounting for Abandonments and Disallowances of Plant Costs*; SFAS No. 92, *Regulated Enterprises-Accounting for Phase-In Plans*; SFAS No. 101, *Accounting for Discontinuation of Application of SFAS No. 71*; and SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of*. Both SFAS Nos. 90 and 92 contain criteria for permitting certain plant-related costs to be deferred for future rate recovery. Costs not meeting such criteria may not be deferred and must be written off. SFAS No. 121 amends SFAS No. 71 to clarify that existing regulatory assets should be written off if they are no longer considered probable of recovery.

The following illustrates how these new Standards have affected TEP. Although the Company was granted authority by the Commission in previous rate cases to defer for future rate recovery certain excess capacity costs associated with Springerville Unit No. 2 (the unamortized balance of which totaled $81 million as of September 30, 1996), such deferrals failed to meet the criteria set forth in SFAS No. 92; therefore, they have been charged in their entirety to expense for financial reporting purposes. No corresponding regulatory asset is reflected on the Company's balance sheet.

Utilities following SFAS No. 71 must continually assess whether they remain regulated entities under definition criteria contained in the Standard. SFAS No. 101 includes the following examples of situations that may warrant discontinuation of SFAS No. 71:

1) Deregulation.

2) A change in the regulator's approach to setting rates from cost-based ratemaking to another form.

3) Increasing competition that limits the enterprise's ability to sell utility services or products at rates that will recover costs.

4) Regulatory actions resulting from resistance to rate increases that limit the enterprise's ability to sell services or products at rates that will recover costs if the enterprise is unable to obtain relief from prior regulatory actions through appeals or the courts.

The thrust of SFAS No. 101 is that, when an enterprise ceases to meet the criteria of SFAS No. 71, either in part (*i.e.* an operating division or product line) or in total, it must discontinue its application and eliminate the assets on its books that were created by regulators. For TEP, the adoption of SFAS No. 101 would result in a net charge against retained earnings totaling some $139 million, based on the balances of regulatory assets and liabilities as of September 30, 1996.

To the extent that Stranded Cost is not adequately addressed in this Electric Industry Restructuring Docket, write-offs beyond those required under SFAS No. 101 may be necessary. Pursuant to SFAS No. 121, a utility subject thereto would also have to determine whether or not its remaining plant assets would be recoverable through expected future market prices. If market pricing is not expected to be fully compensatory, additional write-downs of the relevant assets to reflect the expected revenue levels will also be required.

The impact on utilities of large financial losses and substantially increased business risks would likely be swift and severe. Public utilities financed most of their property, plant and equipment through the issuance of common stock and long-term debt securities. Many utilities also entered into lease agreements that provided a long-term source of financing for generation and other utility assets. Since long-term debt and lease obligations represent contractual commitments, such obligations do not disappear even if the assets that they financed become economically impaired. The impairment of assets due to a reduction of future expected cash flows, without either (i) a commensurate reduction in the company's debt and lease obligations; or (ii) a corresponding increase in cash flows from other sources (*i.e.,* the Stranded Cost recovery mechanism), would severely diminish that company's ability to meet its future cash obligations. Moreover, in certain circumstances, such obligations may include provisions whereby they become accelerated and are due and payable immediately. Such a dilution of financial expectations, combined with the significantly increased business risk, would undoubtedly have an adverse effect on the cost and availability of capital to the company, leaving future financial viability in serious doubt.

All electric utilities will experience the effects of increased business risk and potential for severe financial adversity with the introduction of competition in the generation segment of the industry. However, the consequences to TEP relative to other investor-owned utilities may be significantly greater. Virtually all of the financial progress the Company has been able to achieve during the last five years could evaporate. Although TEP has succeeded in building its equity capital by $189 million since December 31, 1993, the Company's balance of equity capital was only $126 million as of September 30, 1996.

The Company's senior debt securities are presently rated below investment grade at B+/BB- by the major credit rating agencies. These credit ratings serve to limit the market for the Company's long-term debt securities to the high yield market. Low credit ratings also serve to increase the cost of credit enhancements, such as letters of credit, which are necessary to ensure the continued marketability of the Company's variable rate debt securities. With limited prospects for the resumption of common dividends, the Company's ability to raise additional equity capital is also severely constrained. Under these circumstances, the Company is already faced with the challenging task of meeting scheduled debt maturities and refinancing other obligations as required or as warranted by market conditions.

During the period 1999-2003, approximately $250 million of the Company's long-term debt obligations will mature. Letters of credit supporting $805 million of the Company's long-term variable rate tax-exempt debt obligations are also scheduled to expire during the period 1999-2002. In the event that expiring letters of credit are not replaced or extended, the corresponding variable rate tax-exempt debt obligations would be subject to mandatory redemption. Losing this tax-exempt financing would likely increase the capital costs of TEP by approximately $15 million, or about 20 percent, annually. In addition, the Company is also obligated to refinance the debt obligations underlying the Springerville common facilities lease before the year 2000 and will have an opportunity to refinance the high coupon (14.50 percent) debt obligations underlying the Springerville coal handling facilities lease in the year 2002. As a result of such refinancings, the rental payments under each of these leases will be adjusted to reflect any change in interest payments.

Another likely adverse consequence of less than full Stranded Cost recovery affecting utilities' ability to raise capital is the potential reduction in the available bondable property. Utilities issuing mortgage bonds pledge their investments in utility plant assets as the underlying collateral. Typically, mortgage indentures include a plant-to-bonds ratio in excess of one. That means, for every $1 in bonds, something in excess of $1 in plant assets is required as security. For TEP, the ratio is approximately 1.6 - 1. TEP's ability to issue additional bonds is directly affected by the available unbonded utility property. To the extent that Stranded Cost is not fully recoverable and as a result, TEP is forced to write-off a portion of the cost of its plant assets, the Company would be faced with a reduction of bonding capability.

In developing rules for the transition to retail competition, particularly with respect to the issue of Stranded Cost quantification and recovery, the Commission needs to be cognizant of the accounting requirements of the FASB and the potential financial consequences to TEP, as well as the other utilities in the state, if the recovery mechanism is inadequate, or the accounting rules to be promulgated by the Commission otherwise result in large financial write-offs. In TEP's case, less than adequate recovery of Stranded Cost would likely reverse the substantial progress achieved by

TEP since its financial restructuring and would reduce the Company's ability to refinance maturing debt and expiring letters of credit.

G. Other Issues

Another concern that should be addressed by the Commission in considering Stranded Cost recovery is the potential effect that less than full recovery could have on state and local tax revenues. Utilities are among the most heavily taxed industries in any state. The various taxes include sales taxes, gross receipts taxes, franchise taxes, revenue taxes, property taxes and income taxes. All such taxes are driven by either the value of the utilities' assets or revenues. To the extent that significant Stranded Cost is written off as unrecoverable, there will undoubtedly be a reduction of the property tax base. As utility service rates are lowered due to the effects of competition and reductions in rate base, there will be a corresponding reduction in tax collections. As an example, PECO, a major supplier of electricity in Pennsylvania, has informed regulators in connection with that state's inquiry into the introduction of retail competition that the potential impact of unrecoverable Stranded Cost on tax revenues may be as high as $500 million annually. If the introduction of retail competition causes tax receipts from utilities to decrease, the state, counties and municipalities will have to develop alternative revenue collection strategies in a relatively short time period. This situation may include increases in tax rates. TEP has not had adequate time to consider the magnitude of the potential effect of the Rules on Arizona tax revenues, but believes the exposure to be significant.

In addition to the likely reductions in state and local tax collections if less than full Stranded Cost recovery is achieved, there are other tax-related matters that must be addressed in this proceeding. As more fully explained later herein, various providers of electricity in Arizona are treated differently for tax purposes. This creates an unlevel playing field. There will also be the issue of establishing proper nexus; that is, determining which state is entitled to various taxes when electricity is generated in one state and consumed in another. This issue is especially contentious in our industry where the actual flow of electricity is not always identifiable due to laws of physics. Many tax issues will only be resolved by legislation and/or litigation.

H. Stranded Cost Rule - R14-2-1607 - Recovery of Stranded Cost of Affected Utilities

1. Under the Rules, utilities are expected to take steps to diminish Stranded Cost exposure. TEP agrees that utilities should be required to demonstrate reasonable measures to

mitigate Stranded Cost. The problem is to determine what is considered reasonable for any given company. Those actions taken by particular companies that might constitute mitigation will depend on their specific circumstances and relevant market conditions. Mitigation efforts should be evaluated on a case-by-case basis.

The Rules identify expanding wholesale or retail markets as a way to mitigate Stranded Costs. Such activity may not necessarily mitigate (at least to any significant extent) Stranded Cost. It is generally believed that in a competitive power supply market, the clearing price will approach long-run marginal costs. For companies with incremental costs close to, or above market, the expansion of wholesale or retail sales may not have a mitigating effect.

The Rules also identify the offering of a wider scope of services for profit as another means to mitigate Stranded Cost. It is unclear whether this suggested action is intended to include only energy-related activities or is all-encompassing, covering any business activity the utility and/or its affiliates may choose to enter. TEP believes that profits from activities that are unrelated to the provision of electricity in Arizona, that do not require use of the assets that were acquired to serve electric customers in Arizona, and that are potentially strandable, should not be considered as a source of funds to offset Stranded Cost. To the extent profits are derived from energy-related activities and used to reduce Stranded Cost, these services should be governed by the market, not by regulation.

Other approaches to mitigating Stranded Cost may include asset sales, renegotiating uneconomic contracts (as TEP has already done in recent years by renegotiating certain fuel supply agreements), pursuing economic development projects and continually attempting to lower marginal costs (as TEP has done through corporate re-engineering, its Voluntary Severance Plan and similar cost-reduction efforts). It must also be noted that mitigation efforts themselves may lead to additional costs that may become stranded. What constitutes appropriate mitigation for any utility should include consideration of all relevant facts and circumstances. Although, as stated above, asset sales may have a mitigating effect, under no circumstances should a utility be <u>forced</u> to sell or otherwise divest assets to mitigate Stranded Cost.

2. The Rules state that the working group established to address Stranded Cost shall consider a number of factors, including the time period over which Stranded Cost may be recovered.

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Delays in recovery could postpone realization of the benefits of competition and cause a greater risk of not recovering the costs to the detriment of the utilities and its remaining customers.

3. The Rules require utilities to file estimates of unmitigated Stranded Cost along with certain market information. As previously noted, the single, most significant variable affecting the quantification of Stranded Cost is the market clearing price for power. TEP recommends that, as part of its charge in this proceeding, the Working Group also consider just what constitutes "market price." The scope of this inquiry should include an appropriate definition of the market and identification of its participants; the nature of market transactions and pricing methodology; and the time period over which such price is to be determined.

4. Part J of the Rules state that Stranded Cost may only be recoverable from customer purchases made in the competitive market. It further states that any reduction in sales attributed to self-generation shall not be used to calculate or recover Stranded Cost. As previously noted, TEP believes that an across-the-board end user charge is the most effective, efficient and equitable way to provide a reasonable opportunity for utilities to recover Stranded Cost prior to the completion of the transition to retail competition. With respect to customers that may opt to self-generate, TEP strongly believes that they still should bear their fair share of the Stranded Cost burden. Such an approach is consistent with regulatory precedents established for recovering Stranded Cost in the natural gas and telephone industries.

In addressing stranded pipeline costs the FERC determined that all gas transportation customers should participate in sharing the cost burden of the transition to competition, even if the costs were largely sales-related and certain transportation customers were never a sales customer of the pipeline. The FERC's rationale was that it is appropriate to charge transportation customers for sales-related stranded investment because all of those users will benefit from the move to competition.

The philosophy of spreading across-the-board those cost changes to be recognized during the transition of an industry from one characterized by regulated monopolies to one occupied by competitive market participants can also be seen in the FCC's ordered methodology for recovering costs applicable to the interstate portion of non-traffic sensitive plant. To address the potential for uneconomic bypass and unrecovered Stranded Cost, the FCC implemented an end user subscriber

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line charge. In connection therewith, every residential customer connected to the public telephone network pays a $3.50 per month fee, regardless of whether any long distance calls are made.

The justification for recovering retail Stranded Cost from all users of the electric system is no different from the underlying across-the-board approach used in the other industries cited above. The costs involved were incurred under a bundled service regulatory regime and are legitimately recoverable from all customers.

III. LEVEL PLAYING FIELD ISSUES

In its previous filings with the Commission, TEP has been a strong proponent of leveling the playing field for energy providers consisting of existing regulated utilities, cooperatives, government agencies and all new entrants. As the Rules are currently drafted, the core level playing field issues have not been addressed or resolved. There are many problems that arise concerning industry restructuring and how different corporate entities can compete fairly with each other. TEP's responses have been consistent in that the Company believes that these issues need to be addressed before the Commission heads down a path from which it cannot retreat. TEP's comments filed on September 12, 1996, summarized these issues as the following:

> Ensuring a level playing field among competitors involves several concerns, including: (i) allowing regulated utilities to compete on equal footing with unregulated suppliers; (ii) ensuring that regulated utilities do not subsidize their non-regulated business with their regulated business; and (iii) preventing certain quasi-governmental organizations from leveraging their advantageous positions in the provision of competitive services. These problems are multi-faceted and may require both regulatory and federal and state legislative changes as well as continued oversight.

TEP continued to discuss the importance of eliminating the advantages public utilities have over investor-owned utilities. TEP believes that, if these entities are planning to participate in the competitive market, in addition to a retail reciprocity provision, some mechanism must be developed which requires such entities to pay a charge on all power sold in the competitive market which approximates the value of their advantageous position. Such a surcharge should attempt to recover the value of income taxes not paid, lower capital costs associated with a 100 percent debt (no equity) capitalization and any preference power advantages. The funds generated from this surcharge should

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be used to mitigate the Stranded Cost of existing regulated entities and to the extent such funds exceed Stranded Cost, contributed to the funding of any mandated societal benefit charges.

TEP is also concerned that quasi-governmental agencies may choose to sell preference power (owned or purchased) to third parties or affiliates who will have free access to the competitive marketplace. This provides a "back-door" mechanism for quasi-governmental entities to access the competitive markets with lower cost power that undermines the efficiencies of the marketplace. TEP believes that a mechanism similar to the surcharge mentioned above, or perhaps the same charge, must be developed prior to the opening of competitive electric supply markets.

TEP, as well as other parties, identified that there exist peculiarities with various utility providers which could hinder competition. Specifically, the Rules exempt (under certain circumstances) SRP and potentially the cooperatives because of these peculiarities. Further, it is unclear as to whether the cooperatives could compete for customers outside of their service territory while preserving the integrity of their own service territories under the exemption. To the extent that the cooperatives take advantage of this exemption, this would leave only TEP, Arizona Public Service Company and Citizens Utilities to participate. The result of this type of market structure would only frustrate customers and energy providers because of the obvious inequities regarding customer choice and customer information.

Access to customer usage data is a significant issue related to ensuring that all competitors have equal opportunity to compete in the provision of non-monopoly services. If public entities are not required to comply with the reciprocity requirement or the Rules, yet are able to form marketing subsidiaries, the market structure would be distorted in their favor.

In addition to the above issues, the Company believes the following two issues help solidify TEP's comments concerning level playing field issues. These are: (i) the Rules are not strong enough concerning reciprocity; and (ii) The Rules need to change A.R.S. §§ 40-203 and 281 in order to deal with differences between existing regulated utilities and new entrants into the market.

The question of reciprocity is at the heart of leveling the playing field issue. To help provide an example of this, reciprocity was a key component in the recently approved FERC Order 888. There was much debate in the final order about the reciprocity requirement for all transmitting utilities which includes investor-owned utilities, cooperatives, municipals and public power entities. FERC stated on page 370 that:

> We conclude that it is appropriate to require a reciprocity provision in the Final Rule pro-forma tariff. These provision would be applicable to all customers, including non-public utility[1] entities. . . .that own, control or operate interstate transmission facilities and that take service under the open access tariff. Any public utility[2] that offers non-discriminatory open access transmission for the benefit of customers should be able to obtain the same non-discriminatory access in return.

FERC continues on page 373 to explain:

> In response to arguments raised by publicly-owned and cooperatives, we are not prepared to revise or eliminate the reciprocity condition. Our reason is simple and compelling. We are undertaking this Rule and imposing significant responsibilities on public utilities to ensure the Nation's transmission grid is open and available to customers seeking access to the increasingly competitive commodity market for electricity. While we do not have the authority to require non-public utilities to make their systems generally available, we do have the ability, and the obligation, to ensure that open access transmission is as widely available as possible and that this Rule does not result in a competitive disadvantage to public utilities. Non-public utilities, whether they are selling power from their own generation facilities or reselling purchased power, have the ability to foreclose their customers' access to alternative power sources and to take advantage of new markets in the traditional service territories of other utilities. . . . [W]e will not permit them open access to jurisdictional transmission without offering comparable service in return.

TEP agrees with FERC's justifications and believes that they genuinely apply to the current situation concerning the Commission's Rules. TEP's comments on the NOPR that remained in Order 888 were published in the Final Order and are consistent with the Company's comments filed in this Docket. In Order 888, TEP was quoted, "without such access to all eligible customers, reciprocity will fail to achieve true 'comparability.'"

Similarly, no true reciprocity or comparability will occur unless all energy service providers in Arizona have equal access to all customers. Without these two qualities, a robust, efficient and competitive market will not be achieved. The Commission and its Staff have the same responsibility that FERC has in providing a structure that minimizes market distortions and to draft a set of rules that require a provision for reciprocity. As stated above, FERC concluded that it was appropriate to require reciprocity to include non-jurisdictional utilities.

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[1] Non-public utilities are non-jurisdictional utilities, which can include publicly-owned utilities. FERC defines publicly-owned utilities in Order 888 footnote 479, (e.g. Blue Ridge, SMUD, Salt River, Oglethorpe).

[2] Public utilities include FERC jurisdictional utilities, including all Investor Owned Utilities.

IV. LEGAL ISSUES

A. Introduction

The Rules contain numerous legal issues; all of which have been pointed out to the Commission repeatedly and ignored. The Commission must correct the foundational breaches of constitutional, statutory and regulatory standards that cause the Rules to be unfair, unlawful and unwise. To ignore these problems is to abdicate to the courts the Commission's duty to regulate public service corporations and to determine how and when competition in the electric retail industry will be implemented. Thus, the infirmities which continue to plague the Rules include:

1) The Rules are vague.

2) The Rules are confiscatory.

3) The Rules are discriminatory.

4) The Rules unilaterally modify, if not abrogate, the Regulatory Compact.

5) The Rules go beyond the Commission's current authority to act.

6) The Commission has failed to comply with the Arizona Administrative Procedures Act ("APA") in adopting the Rules.

As TEP pointed out in previous filings with the Commission in this Docket, the Rules will not bring about retail electric competition in Arizona because they violate the constitutional requirements of due process and equal protection.

As a proponent of retail electric competition, TEP believes that it is in the best public interest that the Rules be carefully re-crafted so that they <u>clearly</u> set forth the terms and conditions of competition, provide for <u>full</u> and <u>complete</u> compensation for utility property rights that are taken, <u>equally</u> protect all utilities and either <u>uphold</u> or provide for the <u>mutual</u> <u>modification</u> of the Regulatory Compact and are adopted in compliance with statutory requirements. While the time it will take to correct the Rules may appear to cause a temporary setback in the aggressive schedule initially established by Staff for their adoption, this needed step will save months, if not years, of potential litigation and delay in the actual effective date for retail electric competition in this State.

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B. Analysis of the Legal Issues

The federal and state constitutions each provide the protection and guaranty of a) due process of law (U.S. Const. amend. XIV; Ariz. Const. art. II, § 4); and b) equal protection of law (U.S. Const. amend. XIV; Ariz. Const. art. II, § 13). The courts have stated generally that the denial of due process "is a denial of 'fundamental fairness, shocking to the universal sense of justice.'" Oshrin v. Coulter, 142 Ariz. 109, 111, 688 P.2d 1001, 1003 (1984). Also, the equal protection clause of the state and federal constitutions require that all members in a given class be treated equally and that the classification itself be reasonable and not arbitrary or capricious. Pastore v. Arizona Dept. of Economic Security, 128 Ariz. 337, 341, 625 P.2d 926 (App. 1981). As set forth below, the Rules are neither fair nor just.

1. *The Rules are Vague.*

The Rules are vague and, therefore, violate due process because they: (i) fail to provide for or give fair warning as to how many aspects of retail electric competition will be determined by the Commission; and (ii) grant broad discretion to the Commission to set terms and conditions for retail electric competition at a future date but lack standards to restrict that discretion. *See,* Cavco Industries v. Industrial Commission of Arizona, 129 Ariz. 429, 434, 631 P.2d 1087, 1092 (1981); ("Petitioners are correct in asserting that a vague statute may violate due process because it either fails to give fair warning or lack standards to restrict the discretion of those who apply it.")

The general rules and regulations of the Commission have the force and effect of law and are as equally binding as are statutes. Gibbons v. Arizona Corporation Commission, 95 Ariz. 343, 347, 390 P.2d 582 (1964). The courts have consistently held that a law is unconstitutionally vague if: (i) it fails to give a person of ordinary intelligence a reasonable opportunity to know what the law does, so that he may act accordingly; or (ii) if it allows for arbitrary and discriminatory enforcement by failing to provide an objective standard for those who are charged with enforcing or applying the law. Bird v. State, 184 Ariz. 198, 908 P.2d 12 (App. 1995); In re Maricopa County Juvenile Action No. JS-5209 and No. JS-4963, 143 Ariz. 178, 183, 692 P.2d 1027, 1032 (App. 1984); Grayned v. City of Rockford, 408 U.S. 104, 92 S.Ct. 2294, 33 L.Ed.2d 222 (1972).

The Rules, being merely a *framework* of what the finished product should be, do not give a person of "ordinary intelligence" a reasonable opportunity to determine what their consequence will be on key matters impacting the Affected Utilities. This fact is reinforced by the statements of the

Commissioners at the October 8 and 9, 1996 Open Meeting, the public comment sessions held on December 2, 3 and 4, 1996, and the December 23, 1996 Special Open Meeting.

Although the Commission may view the Rules as merely a loose framework, the fact is that the Rules, once adopted become effective law, which will immediately govern the conduct of the utilities and the citizens of Arizona. Indeed, any person not in compliance with the Rules, may be subject to statutorily imposed fines, penalties and liability. *See,* A.R.S. § 40-421 *et seq*. As adopted, the Rules only provide a skeletal sketch of how retail electric competition will be ushered in and then implemented in this State. Too many key factors are now unclear or not addressed, or have been deferred to a later date to then be determined at the discretion of the Commission. It is unjust and unfair to enact vague Rules that do not sufficiently define conduct that is required or proscribed--especially when those affected by the Rules are subject to fines, penalties and other liability based upon their non-compliance with the Rules.

For example, the Rules are vague with regards to the matter of "Stranded Cost." R14-2-1601 of the Rules incorporates unclear and ambiguous terms in its attempt to define Stranded Cost such as "verifiable net difference," "prudent jurisdictional assets," and "market value of those assets directly attributable to the introduction of competition." In R14-2-1607, the Rules state, "The Commission shall allow recovery of <u>unmitigated</u> Stranded Cost by Affected Utilities." (Emphasis added.) Nowhere in the provisions regarding Stranded Cost is there specificity as to the meaning of utilized terms or standards for how the Commission will employ its discretion in the future.

Equally vague is the Rules' treatment of the nature of future and present CC&N. While R14-2-1603 requires that any company intending to supply electric services (other than wholesale generation services) obtain a CC&N, the Rules do not explain what rights and obligations are attendant to the new (or old) CC&N. Indeed, it is unclear how the term "CC&N" is to be interpreted in the Rules or how the Commission will so define them when retail electric competition is implemented in the state.

In addition to these examples, the Rules leave to future definition and determination many other issues including pooling of generation and centralized dispatch of generation or transmission (R14-2-1610); standards for setting rates (R14-2-1612) and quality of service issues.

Because these and other aspects of the provision of electric service are not specified, reasonable minds are not put on notice of how the Rules will affect them. The Rules, once enacted are law and must meet due process requirements at the time of adoption. This cannot be deferred for eventual development and achievement at an unspecified later date. Until the Rules are clarified and put into their proper context, they will not meet due process requirements.

To justify the vagueness of the Rules, the Commission has rationalized that the Rules are a broad framework similar to its competition rules in the telecommunications industry. (*See,* A.C.C. R14-2-1101 et. seq.; Tr. October 8, 1996 at 30.) However, the Commission does not appreciate the drastic distinctions between the scope of current federal and state regulation of the two industries. The electric industry does not have a federal framework governing competition such as the Telecommunications Act of 1996. This act provides many standard procedures and policies nationwide applicable to competition. This act also preempts non-conforming state laws and regulations. In short, many of the gaps that are present in the Commission's loose-fitting telecommunications rules are filed by federal law. There is no such law to flesh out the skeletal provisions of the Rules. Thus, while the Commission's telecommunications competition rules may be workable, they function in tandem with the federal act (and FCC rules). There is no such companion for the Rules and it must be viewed on a stand-alone basis.

2. *The Rules are Confiscatory.*

The manner in which the Rules will handle Stranded Cost and a CC&N will, apparently, take away from the Affected Utilities property and property rights without just compensation. Such action by the state is unlawful confiscation and a blatant violation of due process rights (U.S. Const. amend. V; XIV; Ariz. Const. art. 2, §§ 4 and 17).

TEP believes that Stranded Cost represents an aggregation of costs (the prudence of which has already been established) incurred for the provision of utility service under the obligation to serve in a regulatory framework, that are likely unrecoverable in a competitive market due to market prices that are below embedded costs. *See, Responses to Questions Regarding Electric Industry Restructuring on Behalf of Tucson Electric Power Company* dated June 28, 1996 at 12. TEP further believes that Stranded Cost, which is property of the utility, should be fully recovered by the utility when the state imposes retail electric competition. If it is not, then the state has caused the utility's property to be taken from it for a public use (retail electric competition) without just compensation. Maricopa County v Paysnoe, 83 Ariz. 236, 238, 319 P.2d 995 (1958) ("Private property can not be taken or damaged for public use without just compensation. This means that an infringement on the use of property which would diminish its value in whole or in part is a loss which must be compensated.")

R14-2-1601 and R14-2-1607 of the Rules establish a *framework* that contemplates less than full recovery of Stranded Cost by a utility. Qualified standards such as "verifiable net difference" and "shall allow recovery of unmitigated Stranded Cost" create significant uncertainty regarding the recovery of Stranded Cost. However, the Commission has already ruled on the prudence and cost recovery of assets invested in by Affected Utilities. Ariz. Const art. 15. sec. 3 and A.R.S. § 40-203 authorize the Commission to set the rates to be charged by the Affected Utilities. There is a presumption in the law that investments made are prudent, which can only be set aside by clear and convincing evidence to the contrary. Missouri ex rel. Southwestern Bell Telephone Co. v. Missouri PSC, 262 U.S. 276 (1923); West Ohio Gas Company v. Ohio PUC, 294 US 63 (1935); A.A.C. R14-2-103.1 ("All investments shall be presumed to have been prudently made, and such presumptions may be set aside only by clear and convincing evidence that such investments were imprudent, when viewed in the light of all relevant conditions known or which in the exercise of reasonable judgment should have been known, at the time such investments were made.") During the course of the ratemaking process for the Affected Utilities, the Commission has already determined the prudence of the costs and investments of the utility which have been included or precluded from rate base calculations.

Prior determinations by the Commission as to the prudence of investments in specified assets are res judicata, or in other words, conclusively settled matters that cannot be reversed by subsequent or collateral proceedings (such as the Rules). *See,* Mountain States Telephone and Telegraph Company v. Arizona Corporation Commission, 124 Ariz. 433, 604 P.2d 1144 (App. 1979); Yavapai County v. Wilkinson, 111 Ariz. 530, 534 P.2d 735 (1975); Arizona Public Service Company v. Southern Union Gas Company, 76 Ariz. 373, 265 P.2d 435 (1954). Consequently, investments that have already been determined to be prudent and under the Rules are Stranded Costs and should be unconditionally and fully recoverable by the Affected Utilities.

The Rules are also confiscatory because they preclude any recovery of Stranded Cost after a limited time period. *See,* R14-2-1607.I. The Rules also state that recovery of Stranded Cost can only be made from those customers who are served "competitively," thereby setting the commencement of the recovery to begin no sooner than January 1, 1999. *See,* R14-2-1604.A and

R14-2-1607.F. It is unreasonable to set that which is bound to be such a short time frame for the recovery of what is likely to be millions, if not billions of dollars of Stranded Cost. By doing so, the Rules are virtually guaranteeing that some Stranded Cost will not be recovered, thereby resulting in the confiscation of property of the Affected Utilities.

The Rules also confiscate some, if not all, of the property rights embodied in the Affected Utilities' CC&N. For example, an existing CC&N provides an exclusive right to provide electric service in a geographic area. *See,* James P. Paul Water Co. v. Corporation Commission, 137 Ariz. 426, 671 P.2d 404 (1983). Retail electric competition, by definition, envisions that such exclusivity will not exist. The courts have made it clear that non-tangible property rights such as a franchise (and a CC&N) of public service corporations must be compensated under the law. *See,* City of Tucson v. El Rio Water Co., 101 Ariz. 49, 415 P.2d 872 (1966). However, the Rules do not address, and therefore, do not provide a mechanism for the compensation for the loss of the value of the CC&N. Until the Rules do so, they will violate the due process rights of the Affected Utilities.

The Rules also contemplate that other utilities will have the right to use TEP's distribution system for their own competitive purposes. This also constitutes a "taking" of property and property rights that are now exclusively owned by TEP. The TEP distribution system was constructed and financed to serve TEP's customers in good faith reliance upon the terms and conditions of the CC&N issued by this Commission. The economic value of and ability to use the distribution system is diminished if other utilities are allowed to use it to serve TEP's current (but by then former) customers. Again, the Rules only provide for the taking of TEP's property without any accompanying provision for compensation.

3. The Rules are Discriminatory.

The Rules do not afford all utilities equal protection and, therefore, are discriminatory. (Ariz. Const. art. II, § 13.) From their initial provisions on through the last, the Rules are unlawfully discriminatory because they do not provide for the equal treatment of all members of a recognized class, namely, electric utilities doing business in the state. Garcia v. Arizona State Liquor Board, 21 Ariz. App. 456, 520 P.2d 852 (1974). The Commission, as an agent of the state, must comply with the equal protection clause of the state and federal constitutions in rendering decisions and enacting rules. Bank of Arizona v. Howe, 293 F. 600, 606-7, (Ariz. 1923). However, the disparate treatment afforded Salt River Project ("SRP"), cooperatives and municipal and tribal-owned electric companies on the one hand, and the "Affected Utilities" on the other, demonstrates that there are unreasonable inequalities built into the Rules. The Rules cannot fully afford equal protection to the Affected Utilities and never will until such time as the jurisdiction of the Commission is expanded to include all electric utilities that do business in the state. Gusick v. Boies, 72 Ariz. 309, 234 P.2d 430 (1950) ("The guarantees provided by the federal and state constitutions apply equally to all and they cannot be denied to any one person without weakening the rights of all.")

For example, like SRP, municipally-owned and tribal-owned utilities are not within the definition of public service corporation subject to Commission jurisdiction. (*See*, Ariz. Const. art. XV § 2, not within the definition in the Rules of Affected Utilities and, consequently are not subject to the obligations of the Rules.) It appears, therefore, that these excluded utilities can engage in retail electric competition without being subject to the Rules. Although R14-2-1611 of the Rules attempts to restrict the activities of these non-Affected Utilities, without jurisdiction by the Commission over them, it is doubtful if this section would be enforceable in the courts. Further, reference in that section to various "service territories" would appear to have little meaning if (i) the Commission has no jurisdiction over the non-Affected Utilities; and (ii) there are no longer exclusive certificated service territories under the Rules. Additionally, there will be no equal protection under the law and no reciprocity for the Affected Utilities in situations where electric providers that have no certificated service territory, such as the Western Area Power Authority (or some tribal utilities or SRP's proposed regulated subsidiary), apply for a CC&N in Arizona to provide retail electric service. Moreover, the "invitation" by the Rules for utilities not regulated by the Commission to *voluntarily* consent to the jurisdiction of the Commission for a hearing to determine if, and the terms and conditions by which, they will compete is a proposition that must be determined by the courts or legislature and not the Commission. This was made clear during the Commission's deliberations of the Rules when representatives of SRP and the Commission Staff stated on the record that SRP could not voluntarily submit itself to the jurisdiction of the Commission. Tr. (October 8, 1996) at 46-47. Because the exemption of municipally-owned utilities from the jurisdiction of the Commission is established by the Arizona Constitution and the exemption for tribal-owned utilities springs forth from federal law, expanding the jurisdiction of the Commission to include them cannot, therefore, be changed merely by the enactment of the Rules.

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The Commission has inserted a provision into the Rules that would allow cooperatives to modify the requirements of the Rules (presumably including exemption therefrom), "so as to preserve the tax exempt status of the cooperative or to allow time to modify contractual arrangements pertaining to delivery of power supplies and associated loans." *See,* R14-2-1604.H. In prior pleadings submitted to the Commission in this Docket, TEP has presented valid reasons (such as its rate settlement with the Commission and its two-county financing requirements) for TEP to be allowed to request a modification to or exemption from the Rules. By singling out the cooperatives for this preferential treatment and ignoring TEP and other Affected Utilities with similar concerns, the Commission has unreasonably discriminated among and against Affected Utilities.

4. The Rules Unilaterally Modify, if Not Abrogate, the Regulatory Compact.

The Regulatory Compact has been explained by the Arizona Supreme Court in Application of Trico Electric Co-operative, Inc., 92 Ariz. 373, 380, 377 P.2d 309 (1962), as follows:

> In the performance of its duties with respect to public service corporations the Commission acts as an agency of the State. By the issuance of a certificate of convenience and necessity to a public service corporation the State in effect contracts that if the certificate holder will make adequate investment and render competent and adequate service, he may have the privilege of a monopoly as against any other private utility.

Thus, the State and the Affected Utilities have entered into a compact, evidenced by a CC&N, with mutual obligations and benefits. Simply stated, as long as the utility provides competent and adequate service, it is entitled to the monopolistic right to serve customers in a "certificated" service territory. Indeed, the courts have said that it is the duty of the Commission to protect the monopoly rights of a public service corporation that is upholding the Regulatory Compact. Id. It is in good faith reliance upon the Regulatory Compact that utilities have and continue to invest in plant to serve new customers. It is in reliance upon the Regulatory Compact that utilities serve all qualifying customers within their certificated service territories. However, through the Rules, the Commission would be unilaterally modifying or abrogating the Regulatory Compact. In fact, Stranded Cost is an unfortunate by-product of the modification of the Regulatory Compact.

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The Rules forge new and uncharted territory in their attempt to (i) award a non-exclusive CC&N; (ii) permit retail electric competition in areas currently certificated to utilities that are providing adequate and competent service; and (iii) change the rights of the existing CC&N. There is no present constitutional or legislative authority for the Commission to change the terms of the Regulatory Compact of its own accord. There is no legal precedent for the Commission negating the effect of a utility's CC&N without a showing of the inability to provide adequate service after affording the utility due process. Further, the Commission has never stated (and the Rules do not refer to) any legal source for its ability to alter the Regulatory Compact.

To the extent that the CC&N of any Affected Utility is modified or abrogated as a result of the Rules, the Commission will have done so in violation of due process rights. Further, the courts have firmly stated that before a CC&N can be modified, amended or abrogated, notice and a hearing must be afforded to the holder thereof. *See,* A.R.S. § 40-282; James P. Paul Water Co., supra; (A CC&N holder is entitled to the opportunity to contest any amendment thereof); Application of Trico Electric, *supra*; (The revocation or recission of all or a portion of a CC&N requires strict compliance with due process requirements of notice and an opportunity to be heard). The Rules do not provide for a hearing (and apparently will be enacted without a hearing thereon), yet will change the CC&N, in violation of due process.

TEP is also concerned with an additional aspect of the Regulatory Compact that affects it and other utilities that have entered into a rate settlement with the Commission that includes a rate moratorium. Specifically, the Commission and TEP are bound to honor the terms thereof (including the implied covenant of good faith and fair dealing) but the Commission, by implementing retail electric competition before the rate moratorium is over, will be unilaterally changing the regulatory and economic assumptions upon which the settlement was made. Indeed, if the reality of the implementation of retail electric competition in Arizona had been known during the negotiations of the settlement agreement with TEP, then the terms thereof would certainly have been different than they are presently. TEP would propose, therefore, that it be allowed to phase-in retail electric competition after its rate moratorium is over.

The United States Supreme Court recently issued an opinion that reinforces the integrity and honor of agreements made with the government, such as the Regulatory Compact. In United States v. Winstar Corporation, 116 S.Ct. 2432 (1996), three financial institutions brought claims against the

United States for breach of contract (and other constitutional violations) as a result of the enactment of the Financial Institutions Reform, Recovery and Enforcement Act of 1989 ("FIRREA"), which changed existing rules by limiting the application of special accounting treatment to the acquisition of failing savings and loan institutions. In finding that the government did breach its existing agreements with the institutions as a result of the consequences of FIRREA, the Supreme Court said:

> Just as we have long recognized that the Constitution 'bar[s] Government from forcing some people alone to bear public burdens which, in all fairness and justice, should be borne by the public as whole,'[cite omitted] so we must reject the suggestion that the Government may simply shift costs of legislation onto its contractual partners who are adversely affected by the change in the law, when the Government assumed the risk of such change. Id. at 2459.

The Rules will unilaterally shift the burdens of the Regulatory Compact onto the Affected Utilities in the same way that FIRREA shifted costs to the financial institutions in the Winstar case. Consequently, the Regulatory Compact will be quite different from the agreement originally struck with TEP.

5. The Rules Go Beyond the Commission's Current Authority to Act.

The Rules seem to suffer from isolationism. As detailed herein, there are many instances where the Rules are contrary to, or inconsistent with, the terms and provisions of the federal and state constitutions, statutes, judicial precedent and mandated procedure. These flaws cause the Rules to be arbitrary and beyond the Commission's authority. The Commission can only exercise those powers that can be derived from a strict construction of the state constitution and implementing statutes. Rural/Metro Corporation v. ACC, 129 Ariz. 116, 629 P.2d 83 (1981); Williams v. Pipetrades Industry Program of Arizona, 100 Ariz. 14, 409 P.2d 720 (1966).

By way of example, the Rules will cause Affected Utilities to change their rates independent and apart from any rate case hearing that analyzes the utilities' rate base, return on investment and other financial indicators. Thus the Rules' procedure (or lack thereof) is contrary to the requirements set forth in the case, Scates v. Arizona Corporation Commission, 118 Ariz. 531, 578 P.2d 612 (1978). Although the courts have specified instances, such as emergency interim rate relief, where the hearing requirements may not apply, the circumstances contemplated in the Rules do not fall within any recognized exception to the Scates doctrine. In this regard the Rules will also ignore the established principle that a utility is entitled to a fair return on the fair value of its property devoted to public service. Arizona Corporation Commission v. Arizona Water Company, 85 Ariz. 198, 203, 335 P.2d 412 (1959). Just and reasonable rates meet overall operating costs and produce a reasonable rate of return on the utility's assets. Scates v. Arizona Corporation Commission, supra, at 534. The Rules will, in essence, freeze the rate base and rate of return for the Affected Utilities at the time of determining Stranded Cost, while ignoring the increases in cost and value that will occur over time in the future. This will deprive the Affected Utilities of the opportunity to earn a fair rate of return. If rates are set such that the utility does not have the opportunity to earn a fair rate of return, the rates are confiscatory and unlawful. Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679, 694, 67 L. Ed 1176 (1922).

Also, the Rules improperly infuse the business judgment of the Commission into the internal affairs of TEP. To illustrate, the Rules mandate that specific percentages of the total retail energy sold competitively by the Affected Utilities be generated by solar resources. *See,* R14-2-1609. The law is clear that the Commission is not the party to exercise control over the internal affairs of a utility. *See,* Southern Pacific Co. v. ACC, 98 Ariz. 339, 343, 404 P.2d 692, 694 (1965) (Commission does not have power to manage corporations; management power is incident to ownership); Corporation Commission of Arizona v. Consolidated Stage Co., 63 Ariz. 257, 161 P.2d 110 (1945); State of Missouri ex rel. Southwestern Bell Telephone Company v. PSC, 262 U.S. 276, 289 (1922) (The commission is not the financial manager of the corporation and may not substitute its judgment for that of the directors of the corporation); Appeal of Public Service Co. of New Hampshire, 454 A.2d. 435, 437 (N.H. 1982) (The right to manage the utility is not surrendered by devoting a business to public use). By dictating how much of a utility's energy will be generated by solar resources and setting deadlines for this to be accomplished, the Commission is acting beyond the scope of its jurisdiction. In fact, the Arizona Attorney General has issued an opinion, applicable in this instance, that the Commission does not have the authority to compel public service corporations to make decisions regarding day-to-day operational matters. *See,* Op. Ariz. Atty. Gen. No. I79-099. ("There are no statutory or constitutional provisions mandating joint or cooperative fuel oil purchases by public service corporations furnishing electricity, nor are there any such provisions requiring the Commission to order such purchases, either by rule or by special order.")

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Similarly, there is no legal authority for the Commission to order where or when the Affected Utilities will obtain their power or how it will be generated.

Finally, TEP submits that in order for the Rules to mesh with state constitutional and statutory standards, at least the following provisions would have to be modified from their current form:

1) Ariz. Const. art. XV, § 2 - to change the definition of public service corporation to include municipal corporations and tribal corporations.

2) A.R.S. §§ 40-281 and 40-282 - to change the scope and procedure regarding Certificate of Convenience and Necessity ("CC&N").

3) A.R.S. § 40-203 - to expand the circumstances and procedure by which the Commission can prescribe rates, rules and practices of public service corporations.

6. *The Commission has Failed to Comply with the Arizona Administrative Procedures Act in Adopting the Rules.*

Based upon the Commissioners' comments during their deliberation of the Rules, it was clear that the Commission was determined to enact the Rules by the end of 1996. This fast-track schedule apparently did not contemplate that the Rules will be certified by the Arizona Attorney General pursuant to the APA, A.R.S. § 41-1001, *et. seq.* Specifically, A.R.S. § 41-1044 requires that any rule adopted by the Commission is subject to review and certification by the Attorney General for form, clarity, competency and compliance with appropriate procedures. *See,* also A.R.S. § 41-1057. TEP does not believe that the Rules, in their current state, would be certified by the Attorney General because they are vague, beyond the scope of the Commission and do not meet due process requirements. A rule that is rejected by the Attorney General does not become effective. In Arizona Corporation Commission v. Woods, 171 Ariz. 286, 830 P.2d 807 (1992) the Arizona Supreme Court held that the Attorney General did not have to certify rules promulgated by the Commission that were ratemaking in nature. The Rules, however, reach far beyond mere ratemaking issues in its scope. This is evidenced by the language of Commission Decision No. 59943, which authorized that the Rules be forwarded immediately to the Secretary of State. In the Conclusions of Law set forth in

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that decision, the Commission found that it had authority for the Rules under the following non-ratemaking statutes:

1) A.R.S. § 40-321 (adequacy of service).

2) A.R.S. § 40-322 (standards of service).

3) A.R.S. § 40-336 (require safety devices).

4) "Arizona Revised Statutes, Title 40, generally" (which includes matters such as CC&N).

The Rules impact property rights, contract rights, corporate structures, constitutionally defined jurisdictional issues, internal management decisions and even the future configuration of the electric industry. Although ratemaking is one aspect impacted by the consequence of the Rules, it is not the sole or main focus of the Rules. Certainly, the intent of the Attorney General's review of rules promulgated by the Commission is to set a check and balance in those areas where the Commission does not have exclusive jurisdiction, in other words, non-ratemaking matters. TEP does not believe that the Woods case contemplates that rules impacting a wide variety of regulatory issues (the vast majority of which are non-ratemaking) should not be subject to the check of the Attorney General. Consequently, TEP believes that the Rules are not within the exception set forth in the Woods case and should be submitted to and certified by the Attorney General.

The APA also requires that rules of administrative agencies be promulgated with an opportunity for notice and comment. One of the requirements is that the Commission file an economic (consumer) impact statement. *See,* A.R.S. §§ 41-1021 and 1024(C). This statement is designed to give notice of the economic impact, both positive and negative, of a proposed rule. Unfortunately, the economic impact statement composed by the Commission Staff in connection with the Rules are incomplete and, therefore, inadequate.

On or about October 1, 1996, the Commission Staff circulated an Economic Impact Statement ("EIS") in connection with the Rules. (This EIS was also attached to the Decision as Appendix C.) The EIS incredibly ignored the hundreds of pages of comments submitted by utilities to the Commission that detailed the negative economic impact that the Rules will have on the Affected Utilities and others. Instead of incorporating these comments, the EIS merely states that the possible costs to the Affected Utilities would be items such as "additional record keeping and billing costs associated with deliveries of electricity." To include these matters and ignore the enormous effect of loss of shareholder value and Stranded Cost trivializes the whole purpose of the EIS. In fact, the forced write-off of portions of investments in assets will have a significant impact on: (i) shareholders who, in light of these write-offs, will lose value of their investments; (ii) ratepayers who will be assessed either higher rates or additional fees to compensate to some degree for Stranded Cost; and (iii) citizens of the state who, when the Affected Utilities' tax base is lowered, will lose substantial property tax revenues. A one-sided EIS does not provide the public with the degree of notice (and subsequent analysis) that was intended in the APA. Accordingly, in order to comply with the statutory procedural requirements, the Commission should expand the analysis in the EIS to reflect both the positive and negative impacts of the Rules.

The APA prohibits the adoption of "a rule that is substantially different from the proposed rule". *See*, A.R.S. Sec. 41-1025.A. In determining whether an adopted rule is "substantially different" the following must be considered: (i) the extent to which affected persons should have understood that the proposed rules would have affected their interests; (ii) the extent which the subject matter or issues determined by the adopted rule are different from the subject matter or issues determined by the proposed rule; and (iii) the extent to which the effects of the adopted rule differ from the effects of the proposed rule. Id. at subsection B. The Commission violated A.R.S. Sec. 41-1025 when it adopted the Rules in light of the last minute amendments to A.A.C. R14-2-1611 submitted to and approved by the Commission (hereinafter referred to as the "SRP amendments").

The proposed A.A.C. R14-2-1611 provided that utilities that were not subject to the jurisdiction of the Commission such as SRP could participate in retail competition if all of the Affected Utilities agreed in writing. The SRP amendments extinguished that <u>right</u> of the Affected Utilities and instead inserted a new requirement that hearings take place to determine when and whether non-jurisdictional utilities could compete and that the utility and Commission enter into an intergovernmental agreement.

This last minute change in the Rules renders them substantially different than the rule that was proposed. This fact was recognized by the Commission in the Special Open Meeting. *See*, Special Open Meeting Deliberations at 17; 24-25; and 38. Unfortunately, rather than cure this problem in the manner proscribed by law, namely to either not adopt the Rules or stop the proceeding and commence a new rulemaking docket, and Commission forged ahead and adopted the Rules. This violation of the APA alone is sufficient cause for the courts to strike down the Rules.

To implement the Rules, in their current form and amid an existing framework of federal and state regulation, is to invite successful legal challenges to the Rules and to abandon the notion of retail electric competition in Arizona in the foreseeable future. TEP respectfully submits that the solution to these and the other problems identified herein, can be found in a careful and thorough reconsideration of the Rules. TEP does not anticipate that this will be a protracted process, but it will take time and resources. However, this truly is a situation where the additional time taken to clarify, cross-reference and correct the Rules now will be in the best public interest and the best use of the resources of the Commission and the interested parties. TEP recommends that the Commission look first to obtaining legislative (and constitutional) reform prior to attempting to implement retail electric competition or seeking declaratory judgment from the courts regarding its authority to enact the Rules.

V. TWO-COUNTY FINANCING

The Pima and Apache County Industrial Development Authorities have issued approximately $673 million of outstanding tax-exempt "local furnishing" bonds which benefit TEP's retail customers by reducing significantly the capital costs of serving such customers. The Rules could potentially imperil the tax-exempt status of these bonds and the related customer savings of at least $11 million annually. The Rules should address and consider the implications for TEP and other Arizona utilities which issue tax-exempt bonds on the basis of "local furnishing" (that is, a limited certificated service territory). "Local furnishing" bonds are also referred to as "two-county bonds."

Interest on conduit revenue bonds issued after 1968 by, or on behalf of, state or local governments to finance facilities for privately-owned businesses may be excluded from gross income for federal income tax purposes only if substantially all bond proceeds are used to provide one or more of the types of exempt facilities listed in section 142(a) of the Internal Revenue Code of 1986 (the "1986 Code"). Section 142(a)(8) provides an exemption for "facilities for the local furnishing of electric energy or gas." Section 142(f) states that this "local furnishing" exemption applies only to facilities which are part of a system providing service to the general populace in an area not exceeding the larger of (i) two contiguous counties; or (ii) one city and a contiguous county (*i.e.*, Consolidated Edison Company of New York which provides electric service to New York City and one contiguous county). Treasury Regulations clarify that an otherwise qualifying "local furnishing" system will not be disqualified by reason of its interconnections with other utilities for the emergency transfer of electricity, or because the system includes facilities located outside the area which they serve. Treas. Reg. § 1.103-8(f)(2)(iii)(d).

Internal Revenue Service ("IRS") rulings have provided further interpretations of these "local furnishing" provisions. In general, these rulings have allowed electric utilities to qualify if their facilities have been built no sooner or larger than necessary to meet the needs of the general populace in the utility's local service area and if either of two additional conditions is satisfied:

1) Except possibly during emergencies, the total amount of electricity generated by facilities connected directly to the utility's local grid, together with the amount of electricity generated by the local utility's interest in remote generating facilities (whether or not directly connected to the utility's local distribution grid) during each year (or, in one case, each six months) does not exceed the total amount of electricity consumed in the qualifying local service area. Ltr. Rul. 9447031 (August 25, 1994); Ltr. Rul. 9233004 (May 18, 1992), modified by Ltr. Rul. 9244007 (July 1, 1992); Ltr. Rul. 8915021 (January 12, 1989).

2) Except during emergencies, actual metered flows of electricity at each interconnection point between the local utility's system of wholly-owned facilities which are directly connected to its local distribution grid at all times are inbound to the local system. Under this approach, electricity is disregarded unless it is generated at (or transmitted through) facilities which are wholly-owned by the local utility and which are directly connected to the utility's local distribution grid. Ltr. Rul. 8508050 (November 27, 1984); Ltr. Rul. 8410037 (December 5, 1983); Ltr. Rul. 8319017 (February 7, 1983), modified by Ltr. Rul. 8322008 (February 22, 1983).

TEP's retail electric system provides service to the general populace in portions of only two contiguous counties, Pima and Cochise. However, the total amount of electricity generated by TEP's facilities each year exceeds the total amount of electricity consumed in TEP's service area. Therefore, TEP has not attempted to qualify for the "local furnishing" exemption on the basis of (1) above.

There presently are only four interconnection points between TEP's wholly-owned electric facilities which are directly connected to TEP's distribution grid and the facilities of neighboring utilities: the South Substation, the Vail Substation, the Saguaro/Tortolito Substation and the

Springerville Substation. None of TEP's electric facilities located within the boundaries of these four interconnection points were built sooner or larger than necessary to meet the needs of TEP's local distribution grid. Since 1982, when tax-exempt "local furnishing" bonds first were issued for the benefit of TEP, actual metered flows of electricity always have been inbound at each of these interconnection points, except during emergency circumstances. Therefore, since at least 1982, improvements to TEP's wholly-owned, directly-connected facilities have qualified for Federal tax-exempt "local furnishing" financing.

Presently, TEP has approximately $575 million of outstanding tax-exempt "local furnishing" debt. The interest rate on this debt is reset weekly to track current short-term tax-exempt rates. During 1996, the interest rate on these tax-exempt bonds has averaged approximately 3.5 percent. During this same period, the short-term weekly interest rate on taxable debt of similar credit quality has averaged approximately 5.4 percent. The lower cost tax-exempt debt saves the Company's retail customers approximately $11 million annually. In addition, $98 million of currently outstanding tax-exempt debt obligations were issued by the Pima County Industrial Development Authority in conjunction with TEP's sale and leaseback of Irvington Unit 4. This tax-exempt financing structure also benefits TEP's retail customers. Any legal or regulatory development which jeopardizes TEP's ability to meet the "local furnishing" requirements could result in a loss of these savings and impair the progress the Company is making at improving its capital structure and financial strength.

TEP believes that the "local furnishing" conditions can be satisfied under a competitive retail environment if sufficient effort is made to anticipate and provide for such issues in the Rules. IRS rules relating to "local furnishing" bonds should be thoroughly reviewed and analyzed within the context of retail wheeling, considering the significant adverse impact of losing such financing. FERC, in Order 888, addressed the "local furnishing" topic and structured its rule to allow a "local furnishing" utility and its retail customers to maintain the financing benefits and yet still "open" transmission lines.

The Energy Policy Act of 1992 (P.L. 102-486) amended the Federal Power Act to allow neighboring electric utilities, as well as nonutility generators, to apply to FERC for orders requiring electric utilities to use their transmission facilities to wheel electricity for the applicant. Recognizing that this change might result in unintended, adverse consequences to customers of utilities that have taken advantage of tax-exempt "local furnishing" financing, Congress provided relief. The Energy

Policy Act also amended section 142(f) of the 1986 Code to provide relief in connection with tax-exempt "local furnishing" bonds if non-emergency outbound flows of electricity occur by reason of FERC orders issued pursuant to section 211 or 213 of the Federal Power Act.

On April 24, 1996, FERC issued Order 888 concerning electric industry restructuring, direct access and related issues. Just as Congress in 1992 was concerned that mandatory wheeling of electricity might unfairly jeopardize the tax-exempt status of utilities' bonds, on pages 374 and 375 of Order 888, FERC expresses its intent that the tax-exempt status of utilities' bonds not be disturbed by the new reciprocity rules:

> [W]e recognize that Congress has determined that certain entities in the bulk power market can utilize tax-exempt financing by issuing bonds that do not constitute "private activity bonds" [ftn] or by financing facilities with "local furnishing" bonds. In both circumstances, Congress has entrusted the IRS with the responsibility for implementation and for determining what uses of the facilities are consistent with maintaining tax-exempt status for bonds used to finance such facilities. It is not our purpose to disturb Congress' and the IRS' determinations with respect to tax-exempt financing.
>
> [W]e believe we must ensure that the reciprocity requirement will not be used to defeat tax-exempt financing authorized by Congress. Therefore, we clarify that reciprocal service will not be required if providing such service would jeopardize the tax-exempt status of the transmission customer's (or its corporate affiliates') bonds used to finance such transmission facilities. [ftn][1]

In an analogous situation, this Commission has shown its resolve to preserve for Arizona customers the benefits of federal tax-exemption. In response to the draft rule circulated on August 28, 1996, Arizona's electric cooperatives submitted comments dated September 12, 1996, pointing out that implementation of the draft rule could endanger the cooperatives' federal tax-exempt status under section 501(c)(12) of the 1986 Code. In particular, the Arizona cooperatives pointed out that page 499 of FERC Order 888, at footnotes 499 and 500, expressly provides that a cooperative is not to be required to provide any service that would jeopardize its tax-exempt status. This footnoted provision was intended to create relief for cooperatives that is comparable to the relief expressly

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[1] On pages 376 and 377 of Order No. 888, FERC directs each "local furnishing" utility to include a provision in its transmission tariff, which commits the utility not to contest the issuance of FERC orders under section 211 of the Federal Power Act if it appears that the provision of transmission service otherwise would jeopardize the tax-exempt status of any of the utility's "local furnishing" bonds.

provided and more thoroughly discussed by FERC Order 888 in connection with tax-exempt bonds. In paragraph H.1. of Rule R14-2-1604, this Commission rightly proposed a modification to the draft rule, authorizing cooperatives to request the Commission to modify the schedules described in R14-2-1604(A-D) so as to preserve the tax-exempt status of the cooperatives. However, Rule R14-2-1604 provides no similar relief in connection with transmission service that could jeopardize the tax-exempt status of "local furnishing" bonds or tax-exempt bonds issued for municipally-owned utilities.

Implementation of the Rules could endanger the tax-exempt status of interest on "local furnishing" bonds issued (and to be issued) for TEP if the Rules cause the Company to violate the "local furnishing" requirements specified in IRS rulings. If the Rules were to specify an obligation to serve outside of the two-county area that exceeds any contractual obligation between a willing buyer and a willing seller, such additional obligation could result in a violation of "local furnishing" requirements. This source of low-cost financing could be lost, for example, could be lost if TEP became obligated to serve a customer outside of its existing two-county service territory under the proposed retail wheeling provisions.

Another issue related to the "local furnishing" requirements is the potential stranding of assets financed with tax-exempt two-county bonds. For example, both Springerville Unit 2 and Irvington Unit 4 were financed for TEP with tax-exempt "local furnishing" bonds. The energy from a "local furnishing" utility's generating facility, which is financed with tax-exempt two-county bonds, might no longer be needed to serve the utility's historic retail customers if their energy requirements are supplied by other companies from locally-based retail wheeling transactions. Absent relief, it is possible that the "local furnishing" utility would be precluded from delivering energy from that generating facility outside the utility's service area in either wholesale or retail wheeling transactions.

In either case, if the Rules fails to properly address these or related issues, the Company and its customers could be adversely affected by the loss of low cost financing or the stranding of assets financed with tax-exempt "local furnishing" bonds. TEP and its retail customers would be unfairly penalized.

There are several ways the Commission could address these "local furnishing" issues in modified Rules. One option would be to include a provision, similar to that provided for electric cooperatives, that would authorize TEP and other "local furnishing" utilities to request the Commission to modify the schedule described in R14-2-1604(A-D) so as to preserve the tax-exempt status of interest on such bonds issued and to be issued for these utilities. Another option would be to research the issues further and to include specific language in the Rules which support the preservation of "local furnishing" debt in a retail wheeling environment. For example, specific language could be included that clearly limits the obligation to serve outside of a "local furnishing" utility's existing service area. Finally, should these two options prove insufficient, the Commission should include in its definition of recoverable Stranded Cost any increase in financing costs or the cost of any assets stranded because of "local furnishing" requirements.

As described above, FERC Order 888 directs that a utility is not to be required to provide any transmission service that would jeopardize the tax-exempt status of interest on its "local furnishing" bonds. Although § 142(f)(2) of the 1986 Code provides relief from the loss of tax-exemption penalty if transmission service is provided pursuant to a FERC order which is issued under § 211 or 213 of the Federal Power Act, no federal income tax relief is available in connection with transmission service provided pursuant to a rule or order of this Commission. For the same reasons that it was appropriate for this Commission to modify the Rules to protect the tax-exempt status of cooperatives, the Rules could be modified to authorize TEP and other "local furnishing" utilities to request this Commission to modify the schedule described in R14-2-1604(A-D) so as to preserve the tax-exempt status of interest on such bonds issued and to be issued for these utilities.

VI. OPERATIONAL AND RELIABILITY ISSUES

A. Introduction

The Rules require that distribution unbundling begin with the start of customer choice in 1999. TEP believes the most efficient process to allow customer choice for generation by 1999 is to unbundle the following: generation; transmission; distribution; a stranded cost charge; and a public goods charge. For the purpose of these comments, the following definitions shall apply:

- **Generation** - The production of electrical energy. Bulk electricity is generated at remote plant sites, local plant sites and purchased from the wholesale market for reliable system operation.

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- **Transmission** - The transportation of bulk quantities of electricity on high voltage lines by means of electric conductors from generation sources to an electric distribution system, load center or interface with a local control area.
- **Distribution** - The delivery of electricity to customers connected to the local distribution system. The distribution system includes primary and secondary lines which deliver electricity, and substation and distribution transformers which lower electric voltage from transmission to distribution levels. Distribution also includes metering, meter reading, billing, customer service and other services that the traditional monopoly distribution company has performed in the past.
- **Stranded Costs Charge** - A non-bypassable charge for recovery of unmitigated stranded costs.
- **Public Goods Charge** - A non-bypassable charge for funding public goods programs such as low-income assistance, demand side management, mandated renewables and other programs that the Commission sponsors.

The details involved with unbundling products and services beyond the capabilities of the system will ultimately prevent an efficient transition to competition. TEP believes that complete unbundling of products and services deemed to be competitive should occur after customer choice has started in order to give adequate time to develop clear rules and standards, and for any required technology development and installation to take place.

There are several reasons why TEP believes that complete unbundling of competitive products and services should be left until after customer choice starts in 1999. First, the Commission is attempting to create a new industry structure that contains two key communication links that TEP believes will require significant technological changes. The first link is between the new competitive generation market and the local area control room. The second link is between the local area control room and the customer.

Second, there are reliability issues that will take time to fully address, given the fact that the Rules are attempting to restructure the industry. TEP believes that it is wise to give adequate time to implement new reliability standards, given the changes required in the industry structure and to let the Federal Energy Regulatory Commission ("FERC") changes to be implemented this year take effect before deciding further significant changes.

Third, clear distinctions must be determined between competitive and monopoly products and services in order to allow time to design and install necessary systems to facilitate unbundled customer transactions. TEP believes that customer choice can be implemented on a limited basis without this process being completed. Limited competition parameters for the 1999 start-up date have to be determined quickly to allow for any required system development and installation. Subsequently, work can begin on decisions required to fully define and unbundle competitive products and services by the end of the phase-in period in 2003.

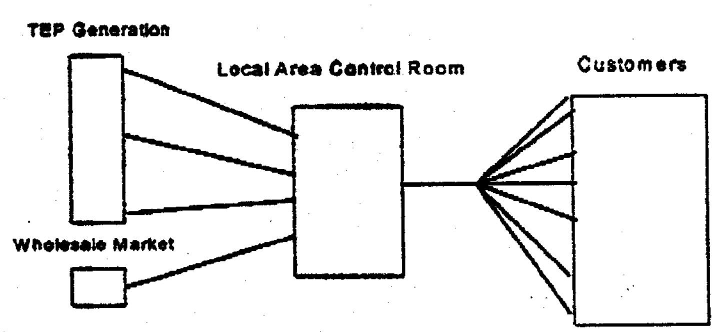
Finally, there are many informational details that need to be addressed prior to complete competitive product and service unbundling. These details involve meter reading, customer information and billing requirements. The decisions surrounding the availability and access to customer data may require significant changes in regards to meters, computer systems and protocols for all competitive players.

The following discussion explains the reasons why TEP believes that the changes required for full competitive product and service unbundling are significant and will take a great deal of time and effort. Further the discussion describes how TEP believes the transition from a regulated to a competitive environment should progress.

B. Industry Structure

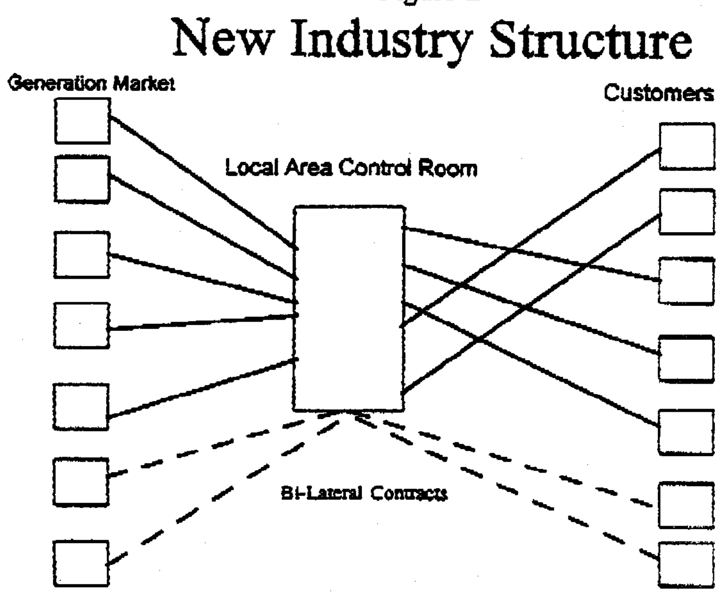
Figure A

Current Industry Structure



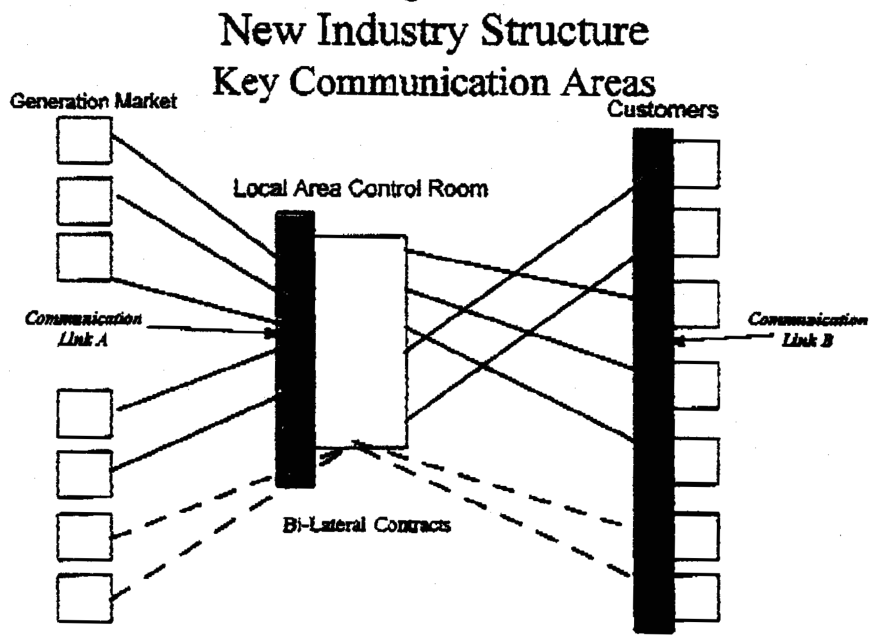
A change from the current regulated environment to a competitive environment requires enforcement of reliability and operational issues at the generation, transmission and distribution levels of the electric supply business. Reliability mechanisms and operational procedures must be adapted to conform to the new environment. Figure A above shows how the industry is currently structured to handle transactions and reliability. Generation, transmission and distribution systems were built to facilitate the delivery of bundled generation supplies and are dispatched and controlled by the local area control rooms of jurisdictional utilities. Customers purchase bundled, firm electric service from one supplier. The local area control room acts to obtain resources and deliver them to all control area customers. Effectively, all retail customers are treated as one customer under the current system.

Figure B



A competitive environment which allows for an endless variety of electric supply and related service options will require significant delivery system modifications. Figure B above shows what such a structure might look like. First, there will potentially be many more generation suppliers. Second, customers will purchase a variety of different types of services (*i.e.*, firm, non-firm, unbundled, etc.) Third, there will be some customers who will purchase energy services directly from a third party through bi-lateral contracts. In this environment, the local area control room will have to match numerous customers with specific supply sources. This type of competitive system requires that the unbundled distribution company have the ability to tie specific resources to specific customers and to drop individual customers or suppliers from the system in the event that their energy supplier discontinues service or their load drops. The local area control room effectively becomes a clearing-house in a competitive environment with significant customer options. This function is vastly different from the current role of the local area control room.

Figure C



Energy management systems, communication systems, billing systems and general system operations will need to undergo significant changes and improvements before the number of independent system transactions dramatically increase. Figure C above shows the two transaction areas that TEP is most concerned with. The first area, Communication Link A, is between the local area control room and the generation market. The local area control room currently controls generation and purchases electricity for its customers on an aggregated basis. The key in the existing environment is to match generation and purchases to the aggregated load. If load increases, the local area control room ramps up generation or purchases from the market and backs off generation or purchases when load falls.

A full choice competitive environment will result in local area control rooms that facilitate transactions between specific suppliers and specific customers and require that the local area control room be able to follow specific customer loads and their respective suppliers moment to moment. If a customer's supplier does not deliver power, then that specific customer will be required to cut its load or purchase alternative supplies. This change from managing a handful of supplies for one customer (total retail load) to a brokering role between many separate customers and suppliers will require significant changes to existing energy management systems as well as more phone lines and people to facilitate customer transactions.

The second area of concern, Communication Link B, is between the local area control room and the customer, and is where all the metering and information coordination issues are concentrated. Full choice competition will require that the customer delivery points (meters) are capable of handling the increased information flows and load control capabilities that go along with the new customer options. The meters will need, among other things, to be capable of tracking load on an hourly or more frequent basis, providing continuous information flow to the local area control room and various suppliers, and communicating billing information to the billing agent. Additionally, the direct access customer interface will need to include equipment that allows suppliers and/or the local area control rooms to curtail deliveries (*i.e.*, to facilitate interruptible or non-firm service.)

TEP believes these issues are solvable, but will require careful consideration and time for development and installation of new technologies. Until such issues are resolved and systems are re-engineered, services must be deliverable with existing facilities or Affected Utilities must implement those changes that can be quickly added prior to the provision of a competitive service.

Because of these changes to the industry structure, TEP believes that the quickest and easiest solution is to limit the type of access allowed in the initial phases of the industry restructuring. Using our illustrations, an example of limited access would be to allow only Communication Link A to be opened to the competitive environment starting in 1999. The purpose of limiting the initial competitive options is to allow competition to begin quickly and in an orderly fashion while allowing additional time to sort out details which must be considered before a wider array of options become available. One example of limiting initial competitive options would be to allow customers to purchase a base supply from the third party market (*i.e.*, 100% load factor portion of their load) but require back-up supplies, load following and other ancillary services to be purchased from the jurisdictional utility. In this phase, billing and metering would be required distribution services from the jurisdictional utility. This would allow competition to begin without requiring significant operational changes.

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Figure D

Transitional Industry Structure

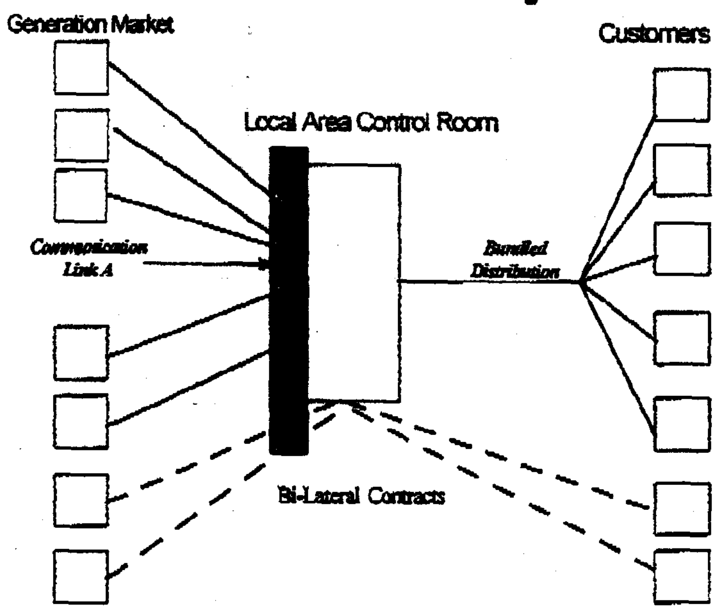

Figure D above illustrates what the transitional industry might look like. By keeping most of the distribution functions in a regulated monopoly setting, competition can be initiated and time will be given to the areas that need more development and definition. In this limited access structure, bilateral contracts will be a viable option for some customers that choose to immediate direct access to the competitive market.

TEP has provided a possible time line for distribution unbundling in Appendix A. The issues surrounding unbundling the distribution system are diverse, but TEP believes that most of the problems can be resolved through clear, standardized rules along with time to implement the necessary changes. Some issues such as reliability are black and white and there will be little controversy as to the best solution. Other issues such as whether customer data is public or private information will require much debate. Additionally, there are some issues which are not controversial, but will require significant time for implementation to take place such as new metering systems. Industry standards and protocols will be important for flexibility and to promote competitive efficiencies.

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1. *Reliability*

The responsibility for reliability currently rests on the bundled electric supplier. Retail suppliers coordinate all components of reliable service from generation to customer meters. Generation and transmission reliability are guided by the Western Systems Coordinating Council ("WSCC") and the National Electric Reliability Council ("NERC"), while distribution reliability is largely guided by state regulatory bodies. Historically, electric supply has been extremely reliable with oversight from NERC, WSCC and state regulators. However, on a day-to-day basis, regulated utilities have provided oversight in compliance with the obligation to serve and mandated service standards.

In the future, assuming competitive markets for at least the generation component of the electric supply business, different parties may be responsible for reliability at the generation, transmission and distribution levels. The distribution supplier is likely to be responsible for reliability from the local area control room to the meter, regulated transmission providers will be responsible for high voltage transmission reliability and competitive market suppliers will be responsible for generation reliability. This type of electric supply market may be much more difficult to police from a reliability standpoint due to the different types and increased number of players involved with providing service from the generation source to the meter. The WSCC, an organization that largely relies on member cooperation, may not be an effective reliability agency in a competitive generation market. NERC and state regulators probably will not be effective reliability monitors in competitive generation supply markets as they do not have jurisdiction over all the generation suppliers. Additionally, none of these organizations provide day-to-day oversight similar to the current regulated utility.

The FERC supports the concept of Independent System Operators ("ISO") as a mechanism for transmission owners to transfer the obligation for reliability and access to an unbiased third party. Given the broad reliability concerns and complexities of the electric supply system discussed above, TEP believes that an ISO type of organization is needed to facilitate generation and transmission reliability in a competitive electric supply market. Such an organization could become the clearinghouse for generation and transmission supply transactions and oversee the reliable delivery of power to distribution suppliers.

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The ISO should function both as an independent grid operator and an independent power pool operator. The ISO does not need to be a power pool in the sense that it dispatches generation but should act as a "clearinghouse" for all electric transactions. This would help reduce some of the burdens that would land on the local area control room given distribution unbundling. It should have the responsibility and authority for scheduling transactions on the transmission grid, as well as ensuring the reliability of the supply and transmission systems. In the course of conducting business, the ISO should establish and enforce standards, procedures and rules that are needed for the reliable and efficient operation of the transmission system and the supply market (assuring, for example that adequate operating and spinning reserves are maintained.) Additionally, oversight of the ISO by the WSCC, FERC and state regulators would likely be more effective than working with individual market competitors.

The ISO should be fully operational when competition begins so as to clearly establish the responsibilities, authorities, standards and procedures that are critical to the reliability of the bulk power systems in Arizona and its effects on other systems in the West. The ISO should be a non-profit entity, with direction from a small board which is representative of the suppliers, customer groups and distribution companies. Owners would retain ownership of their transmission and turn over to the ISO its operating responsibility.

In addition to creating an ISO, the reliability work group needs to establish distribution reliability standards. It may be necessary to establish new ancillary services for the distribution system once complete unbundling at the distribution level begins. Standards need to be established for the following services, among others:

a) VAR support
b) Load following
c) Capacity back up
d) Metering
e) Communication networks
f) Load shed contingency plans
g) Two county power flow

The reliability work group should first focus on issues pertaining to customer choice for generation starting in 1999, and then work on the details of the unbundled distribution company.

This effort should be coordinated with the work group established to define which services should be unbundled from the distribution company as discussed above.

2. *Distribution Functions*

The responsibility to maintain an adequate and safe distribution system should remain part of the distribution company's mission. Clear distinctions between the services that the distribution company currently provides that could be competitive and services that should remain monopolistic must be established by the onset of full deregulation in 2003. During the transition phase, the distribution company would most likely provide the same services as it does today, but start to prepare for the unbundling process. The Commission should establish a review process to evaluate which services fall into the competitive arena and which services should remain with the regulated distribution company. This should be an ongoing process since it is possible that as new technologies and systems are developed, services should be moved from the regulated distribution company to a competitive environment.

A "bright line" between which products will be considered regulated distribution services and which products will be considered competitive is essential for successful unbundling. The main reason for this distinction is for rate design and pricing development. Affected Utilities may have different strategic initiatives depending on these distinctions. This could include the decision to outsource certain services for efficiency reasons such as billing, meter reading or other services currently associated with the regulated distribution company. How costs are allocated between services will be critical to making important decisions both in terms of human resources and product development.

3. *How Far to Unbundle Distribution*

Both the California Public Utilities Commission ("CPUC") and the New Hampshire Public Utilities Commission ("NHPUC") have started implementing plans to provide customer choice in their respective states by 1998. The Ratesetting Work Group ("RWG") in California has created five options for potential unbundling. There is consensus in the group that at the least generation, transmission, distribution, competitive transition charge and public goods should be unbundled in order to create a competitive market for generation. However, the RWG has struggled to determine the extent to which distribution services need to be unbundled (if at all) in order to support the CPUC's stated policy goal of making direct access available to customers of all sizes and classes.

Appendix B lists out the five options and some of the detail questions the working groups are dealing with.

On September 10, 1996 the NHPUC issued a preliminary plan on industry restructuring. The NHPUC decided that at first, simple unbundling is sufficient for customer choice, and states:

> In order for consumers to choose their electricity provider, utilities must first unbundle retail electric services and rates. The process of unbundling involves segregating each of the various bundled service components and pricing the monopoly components separately. Enumerating these components and understanding who provides what service at what price is the first step in determining how markets will be structured.
>
> At a minimum, we believe utilities should unbundle their electric rates and services into generation, transmission, distribution and conservation and load management services. We do not preclude a more comprehensive unbundling at a later date. However, we remain concerned that the failure to further disaggregate distribution services will stifle the development of competitive markets and discourage innovation in the areas of metering, billing and customer services.

Both of these state commissions are struggling with the question of how far to unbundle the distribution company in order to affect customer choice by January 1, 1998. Although California is still undecided as to the states direction, if the Commission continues with the minimum requirements for customer choice, the goal of moving towards a competitive environment will not be delayed.

The issues other state commissions are having difficulty addressing include customer information. The Commission will have similar issues to address and should take the time required to appropriately analyze the available options. The meter is the only physical link between the customer and the energy provider and is used to establish an accurate revenue stream for the energy provider and an accurate usage measure for the customer. Current technology only allows this measurement to happen after the fact. A monopoly business performing this function can easily maintain the proper data base required for tracking each customer's usage level and therefore, its bill. Opening these distribution functions up to other providers at the same time as initiating customer choice for energy providers creates a series of issues to resolve, including but not limited to:

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a) Metering:

i) The need for smarter measurement devices considering the increased number of transactions.

ii) The frequency of billing information required (*i.e.*, hourly, monthly or other levels of frequency.)

iii) The need to establish meter reading and operating standards.

iv) The need to establish who is responsible for maintaining and reading the meter.

b) Customer Information:

i) The need for market information versus protection of customer privacy.

ii) The need to coordinate information between different service providers and create information standards.

iii) Compensation to existing utilities for providing market information.

iv) The need to establish "ownership" of customer data once an open market is established.

c) Billing Requirements:

i) Who will be responsible for credit management.

ii) Who will be responsible for billing corrections.

iii) How will customer deposits be handled, especially for large subdivision additions.

There are a multitude of related issues that are listed in Appendix C and Appendix D. TEP believes that these issues should be the responsibility of workshops and evidentiary hearings scheduled to commence this year. The lists are included in this filing to indicate some of the details that need to be addressed in order for customer choice to be effective.

The decisions of how far and when to unbundle the distribution system are vital to the next stages of restructuring. TEP believes all services which are competitive should be unbundled from the distribution company allowing the competitive process to control prices and create operational efficiencies. However, TEP is more in-line with how NHPUC is proceeding with distribution unbundling. TEP suggests that the Commission continue to work towards providing the necessary changes to create a competitive generation market starting in 1999, but allow time to investigate complete distribution unbundling. What TEP is requesting from the workshop and evidentiary hearings are precise standards and timing for the unbundling process to occur in order to minimize the chaos that is created by the restructuring.

C. Conclusion

TEP is a firm proponent of industry restructuring and moving towards a competitive environment and would like to work with the Commission to help develop a clear plan to achieve this goal. Delaying the process of complete unbundling will not slow down or harm this process. In fact it should create an easier transition for customers at all levels by leaving some of the smaller but important details to a later phase. TEP believes that electric supply should be unbundled in 1999 to the point that allows customer access to competitive generation markets within the constraints of supply mechanisms and technology that exist and are in place at that time. Additional unbundling should occur after all competitive market structure issues have been determined and necessary technology has had adequate time for development and installation.

The time line TEP provided should give the Commission reasonable assurance that the ultimate goal is to unbundle all potentially competitive services without putting system reliability at risk or harming customers. The main reasons for delaying the unbundling of certain services are:

1) Many of the required technology changes will be driven by the market structure that is allowed and thus appropriate technology cannot be developed and installed prior to the market structure being defined.

2) The communication links between the new generation market, the local area control room and individual customers required for competitive access will take significant time to develop and implement and cannot be dealt with prior to determination of an appropriate market structure.

3) The reliability issues will take some time to fully address. An ISO, for example, will take significant time to develop. Consequently, the need for such an entity and the general purpose thereof must be determined quickly.

4) It is important to establish clear distinctions between competitive and monopoly products and services provided by the distribution company and other energy suppliers. Each individual determination of competitive and monopoly products and services will require separate consideration as the resulting market structure and technology impacts will vary from product to product.

5) There are many details that need to be addressed prior to full unbundling of competitive services. These details include meter reading, customer information and billing requirements. Decisions regarding items such as ownership of, and access to, customer data may require significant changes to meters, computer systems and industry protocols.

TEP's primary concern is that the horse must come before the cart. In other words, decisions regarding what is competitive and how competitive service levels will be monitored must be made before the development and implementation of the appropriate service definitions, tariffs and system changes required to complete the transition to a competitive electric supply market. The Rules do not resolve these issues, nor do they provide a mechanism for so doing before its implementation. Accordingly, TEP submits that it is in the public's best interests that the vital issues raised in these comments be resolved <u>prior</u> to the Rules being adopted and becoming effective. Consequently, TEP requests that the Rules be amended, if possible, to cure the defects (and fortify its strengths) as outlined in its comments in this docket.

VII. CONCLUSION

In TEP's June 28, 1996 *Response to Questions Regarding Electric Industry Restructuring,* the Company stated:

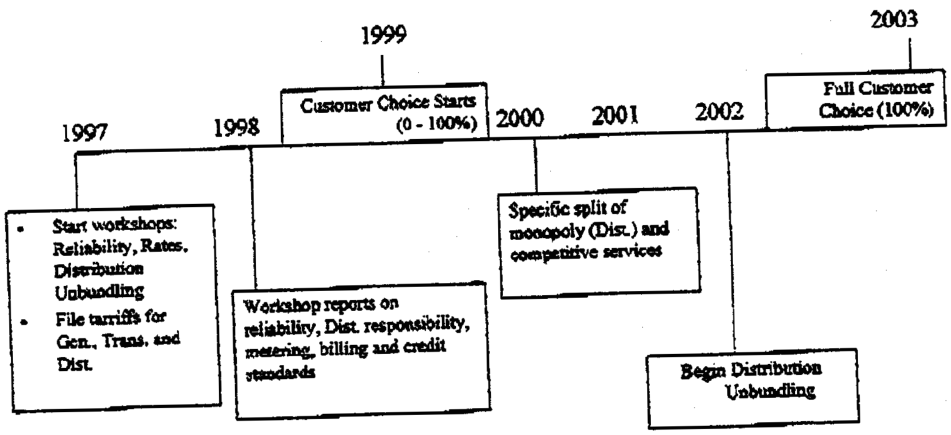
> TEP believes that the Commission and the utilities must work together to ensure that the transition to full competition maximizes the benefits to customers without unduly harming the utilities and their shareholders. To this end, the parties must first resolve some of the major issues to create an atmosphere where all energy providers can compete equitably. This includes developing an equitable recovery mechanism for stranded investments, resolving the public power issue and determining appropriate industry structure. Until these issues are resolved, it will not be possible to create an equitable and efficient marketplace.
>
> Although the Commission has held workshops, and we encourage that more workshops be held to discuss the comments filed in this Docket, it should consider holding public hearings on the major issues. Legislative issues should also be identified as it does not appear that the Commission will have all the necessary authority to create a fully equitable and efficient marketplace without legislative changes. Finally, the Commission should start working with each electric utility in the interim to discuss the tools necessary for the utility to be properly positioned for competition.

Unfortunately, the process (or the lack thereof) that has been undertaken since June 28, 1996, and the resultant Rules that were adopted, have not accomplished any of the objectives identified by TEP (and others) necessary to bring about retail electric competition in Arizona in the orderly and equitable manner as described above. Other jurisdictions, including California and the FERC, have spent considerable time to study the issues, build consensus and seek meaningful input through technical conferences and public hearings. Instead, the Commission has adopted Rules without studying the specific issues raised concerning the Rules, without attempting to build any kind of consensus and leaving the technical conferences and public hearings for some future time. Additionally, it seems the Commission is unclear as to how it wants to proceed on some of the major issues. For example, when the Rules were first proposed on October 1, 1996, SRP was not included. After the Working Session of the Open Meeting held on October 8, 1996, SRP was included under certain circumstances. At the December 23, 1996 Special Open Meeting, the circumstances governing the participation of SRP changed again. These kinds of issues should not be decided "from the seat of the pants." They need to be thoroughly examined before being codified in Rules that have the force and effect of law.

TEP has identified herein many of the primary objectives of retail competition that must be addressed in any rule, as well as the primary Stranded Cost, operational, reliability, pricing and legal implications that must be resolved prior to the implementation of definitive rules. Because these primary issues remain unresolved vis-à-vis the Rules, TEP urges the Commission to follow the leads of other jurisdictions to resolve the major issues first. TEP, therefore, proposes that following the issuance of a Stay, the parties work together to build consensus, perhaps using the Rules as a platform in order to bring an orderly transition to competition in Arizona. The issues left unresolved by the Rules are a threshold to a system that can be implemented optimally, legally and equitably.

Appendix A - Time Line

Restructuring Time Line



Appendix B - California Restructuring Issues

Option 1 identifies the Track 1[1] items as Generation, Transmission (including ancillary services), Distribution, Competition Transition Charges and Public Goods (collectively, the "Five Consensus Items"). This will require the investor-owned utilities to separate their bundled revenue requirements into these five functional categories, a process involving refunctionalization of assets and direct assignment and allocation of common costs and administrative and general expenses. Proponents believe that determination of Track 2 items, including the threshold policy and methodological issues associated with such unbundling of distribution products and services, must be deferred until after the start of direct access in order to avoid any risk of delaying the implementation date.

Option 2 calls for unbundling of the Five Consensus Items to meet the January 1, 1998 deadline for Direct Access. In addition, Option 2 identifies a separate, parallel process within the Ratesetting Working Group process to identify potential distribution services that are candidates for unbundling. Under this option, parties will begin now to evaluate which Track 2 items are candidates for post-January 1, 1998 unbundling, determining what Commission decisions are necessary for additional unbundling to proceed, specifying the needed cost studies, and engaging in essential groundwork. Proponents believe that Option 2 will best balance the need to implement Direct Access by January 1, 1998 with the desire to address the possible unbundling of distribution services.

Option 3 supports unbundling the Five Consensus Items and further unbundles selected distribution services under Track 1. Option 3 selects certain revenue cycle services for Track 1, chosen from metering, billing, customer and uncollectibles services. Services are screened according to criteria which will differentiate between competitive (retail) and monopoly Utility Distribution Company ("UDC") services and determine whether the UDC is or is not the default provider. Monopoly services remain bundled with exclusive UDC franchise rights. Other competitive distribution services are identified, prioritized and unbundled after January 1, 1998 (Track 2) as new retail products and services are identified. Option 3 unbundles UDC cost savings (credited to the bill)

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[1] Track 1 items include services that need to be unbundled to provide customer choice by 1/1/98, Track 2 items are services that can be unbundled after 1/1/98.

when retailers, rather than the UDC, provide the service. Where the UDC is the default provider, UDC cost savings are based on marginal attributable costs. Where the UDC is not the default provider, UDC cost savings are based on higher average attributable costs. Proponents believe that Option 3 meets CPUC goals and achieves a balance among the nine evaluation criteria defined in this report to ensure timely direct access and support retailing.

Option 4 provides a comprehensive, phased distribution function unbundling process in which the component services included in the retail distribution function now restricted to the UDC are ultimately divided into three categories: i) unbundled and competitively provided by multiple organizations, which might include the UDC; ii) unbundled, but provided exclusively by a monopoly at two or more levels of quality at the customer's choice; and iii) bundled monopoly services required of all customers. The process begins now with an assessment of what services fit into each category and then determines when to make these changes. A limited number of services may be appropriately unbundled by January 1, 1998. The proponents believe that the process should begin by unbundling some services duplicative of direct access providers under monopoly supply in order to develop the intelligence needed to make more informed judgments about the suitability of full scale competitive unbundling. Their view is that, while distribution function unbundling is a key element of consumer choice, no party has sufficient information to judge what end state can be supported by markets. This option does not require a priori judgments about which services can be successfully shifted to the unbundled, competitive market and is proposed to be an orderly process under which a succession of unbundling and competitive supply opportunities can be tested, while preserving the possibility of a regulated monopoly as the end state for some services.

Option 5 proposes that three features be incorporated in the CPUC's end state vision of the restructured industry. First, unbundle certain distribution services, thereby creating a first tier of retail service providers within whom the obligation to serve rests, one member of that group being the utility's retail arm. Participation in that group of retail service providers would be restricted to firms meeting financial and operating standards. In the end state, most distribution services would be both unbundled and offered competitively. Second, unbundle several of the credit protections used by the utilities such as the uncollectibles account, customer enrollment issues and customer terminations for failure to pay. Third, permit the prepayment of the tariff charges, inclusive of full prepayment of embedded ratebase, as a payment option within all electric tariffs, while changing no other features of the tariff's terms of service. Implementation/testing of these proposed changes would be sequenced throughout the restructuring phase-in period. Proponents believe that a firm commitment to accomplish these changes within a reasonable time frame is more important than the precise order or timing of them. Proponents further believe that these proposed changes are necessary to ensure that all groups of customers have access to competition and that most parts of the bundle, as perceived by the customer, are open to competitive forces.

Appendix C - Direct Access Work Group's ("DAWG") Data Requirements

Data to Support Outage Detection and Restoration

Utilities need real-time notification of outage conditions in order to dispatch crews and restore service to customers. Utilities also need outage restoration information and "power on" checks to significantly improve customer service quality and efficiency.

Data to Support Turn Ons And Shut Offs

Utilities require opening and closing readings when customers move into or out of a premises. The reads are on-request. Utilities also prefer to monitor vacant residence for idle consumption.

Data to Support Power Quality Monitoring

Power quality data is desired by certain groups of customers to ensure that energy service quality is maintained for critical production operations. For example, voltage quality and harmonics control may be required for a factory's service.

Data to Increased Scope of Operations

Many believe that two-way communications are essential to create the benefits of increased scope of services and to leverage customer opportunities to participate in the competitive market. The distribution system operator, for example, may benefit from having customer-specific data and two-way communications with the Schedule Coordinator.

Data to Detect Meter Tampering and Theft Detection

Meter tampering and theft detection are operating costs incurred by all utilities; the monitoring and control of which would lead to more efficient operations.

Data on Interruptible Loads and Demand-Side Management

Real-time meter reads are used by distribution companies on interruptible loads during curtailment periods to monitor and verify contract compliance. Daily load profiles are used by distribution companies to monitor demand-side management applications.

Data on Power Quality Monitoring

Where necessary or desired, meters could be installed to monitor power quality: spikes, surges, sags, drop-outs (zero voltage), over voltage, under voltage (brown outs) and harmonic distortion. When a power quality event occurs out-of-band, alarms could be triggered automatically

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to notify the customer and UDC. With that information, steps could be taken to mitigate the power quality problems.

The DAWG group also determined that the following systems standards are necessary to ensure that requirements are met in the following areas:

1) Metering and data communications:

   a) Compatibility of equipment and systems provided by different entities
   b) Integrity of metering and data communications - the system works as desired
   c) Development of licensing/certification requirements
   d) Enforcement of adopted standards
   e) Security of meter data
   f) Unauthorized Access
   g) Theft prevention/deterrence of tampering
   h) Timeliness of meter data delivery/access
   i) Safety—both public and employee
   j) Accuracy of metering systems – initial and ongoing

2) Performance of Work:

   a) Metering equipment operations
   b) Metering equipment installation
   c) Metering equipment maintenance
   d) Metering equipment testing - procedures and frequency
   e) Licensing of metering installers
   f) Coordination with local electrical inspection authorities
   g) Meter vendor certification

3) Hardware and Software:

   a) Meter communications protocols
   b) Meter reading systems
   c) System integration
   d) Data storage

e) Data access

f) Data transfer systems and protocols

Meter programming systems and protocols

Appendix D - Detail Customer Information Issues

A. Customer Information

1. Need for Market Information

One of the more difficult issues that the Commission will need to resolve is how to balance the needs and rights of customers to protect their privacy against the needs of the marketplace for information. Adequate flow of market information to all competitors is necessary for efficient market operation, but inappropriate use or release of customer information could have a harmful effect on customers. To control information flow too far in either direction could undermine the goal of restructuring.

The supply of electricity requires certain information on customers and their energy usage for the purposes of rendering an accurate bill for services, collecting for services and for operating the system. In addition, utility sales and marketing departments use customer data to support public policy programs and customer retention efforts. In the regulatory framework, these were the primary uses for which customer data was collected - regulatory oversight and system planning. In the competitive environment, the main purpose for using this information will be for marketing.

A fundamental assumption of restructuring is that customers will benefit from competition; an assumption that is based on the economic theory of competitive markets and requires that market participants have ready access to information about the market. Specifically, for markets to function efficiently, customers need information about the products and services available, and providers need information about the demands of potential customers. An obvious problem, however, is that a release of customer information intended to reduce the barriers to entry and enhance competition may result in undesirable marketing practices or competitive harm to businesses. The rights of customers to information privacy should not be compromised in the effort to stimulate competitive markets.

On the other side of the fence, a customer will require comparison information concerning energy service providers in order to make informed decisions. The issues surrounding the debate in California about aggregators requiring marketing information in order to compete, also pertain to customers requiring information to compare new energy providers. Information about new energy providers must be presented in some comparable format. A customer must be able to compare

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"apples to apples" when shopping for specific products. Again, the Rules need to be specific concerning information about basic services.

Before the Rules are implemented, the Commission must make some major decisions concerning the access of customer information to new energy service providers and vice versa. In California, DAWG concluded that the following questions must be answered by the CPUC in order to implement a plan to access customer information:

1) Establishing rules and mechanisms to ensure fair or comparable access by competing retailers, which requires answering these questions:

   a) What kinds of customer information should be made available?

   b) Which parties should be eligible for access to customer information?

   c) By what mechanism should it be made equally available to all qualified parties?

   d) How can we prevent privileged access by some competitors?

   e) How much will information access cost, on which entities will costs be imposed, and how should costs be recovered?

2) Protecting customer privacy, which requires answering these questions:

   a) How should informed customer consent to release information be obtained?

   b) What rules should govern appropriate use of customer information by retailers?

   c) How can rules be enforced and complaints be quickly and fairly resolved?

2. Information Between Different Service Providers

One concern that TEP has is the coordination efforts that will be required between different service providers for customer information. There needs to be an established standard for data requirements, type of data available and responsibility of each service provider to furnish customer data. Particularly in the credit area, the Commission and or work groups need to determine how to distribute customer payments between multiple providers of energy or services if partial payment, delinquent payments or deposits are made by the customer.

It can be assumed that each Affected Utility has its own customer computer system and that these systems are not universally compatible without modifications. Although standardizing data requirements is not a show stopper, consideration must be given to the cost of modifying systems or the possible requirement for new system installations. When FERC established its OASIS requirements, most utilities needed to purchase new software or develop the product in-house at their own expense.

As discussed above, some of this type of information fits into the customer privacy issue, and consent forms will need to be provided to share information between service providers such as credit history, delinquent payment history and other sensitive data. Some customers could take advantage of the system and switch energy service providers in order to avoid back payments. In this situation, sharing credit information will be useful to all competitors, yet customers may feel that their privacy rights are being violated.

The Rules also need to establish who gathers the information and their responsibility to share or analyze them for others. For instance, if a customer has different providers for energy, transmission, distribution and ESCO services, and the customer requests load, outage, power quality or other types of analysis, service providers have to access the same information and be able to provide useful information to the customer. This could require vast amounts of data storage and widespread use of information access and analysis tools especially if data will be stored on an hourly basis as mentioned in the metering section.

3. Market Information and Data Ownership

The issue of who "owns" or who should control previous monopoly customer data is another topic that will require considerable discussion. This is another gray area that will cause parties on all fronts major concern. For analysis purposes, it is helpful to focus on two opposite sides of the issue, although there are certainly more than two positions to this issue. Some parties assert that customer data is the property of the utilities that have collected and maintained it. Since the utilities collect this data as a matter of necessity and incur business expenses in so doing, they own the data. Others disagree with this viewpoint, arguing that the business expense is borne by ratepayers with little or no risk borne by shareholders in the process, and that the necessity of data collection does not imply ownership.

Affected Utilities will declare that the information proposed to be made available to competing providers has been collected and maintained by the utilities, and the process of making it available would impose some costs on them. At the very least, there will be some costs associated with obtaining customer consent to release information and with preparing the data and delivering it to eligible providers. The implementation of information access must assess the nature and magnitude of all relevant costs, and provide means to recover those costs and compensate the appropriate parties.

Another option to consider is that customer information is owned by the customers themselves, and that if any monetary return is realized from the economic value of the information that return should be shared with customers. This information is also a necessity to establish a fair and efficient market and transform the industry to one of competition. At least in the initial stages, customer information should readily be available to any new entrant.

B. Billing Requirements

Once competition is allowed to start and there are multiple service providers to a single customer, there must be an answer to the question of who provides the billing for that customer's energy services. The quickest and simplest solution will be to have the distribution company provide this service. Since the customer must receive services from the distribution company for wires services, it makes sense for the distribution company to simply continue billing for services it supplies to the customer and add to that any additional services provided to the customer by the market.

Conversely, the Rules state that billing and credit services are competitive and that companies providing these services do not need a Certificate of Convenience and Necessity. This implies that any company can set up shop and sell billing and credit services. Therefore, it will be necessary for the Rules to state specific standards concerning the data requirements and bill processing.

1. Credit Management

In the new competitive environment, credit management will need to be coordinated between different energy providers. Standards will need to be established if a customer has multiple providers and only contributes partial payments each month, or if the customer is in arrears. Another issue is when a customer leaves a certain energy provider and still has an outstanding balance. One possible solution is to examine the telephone billing and credit systems already in place and look at how these companies handle different suppliers and different customer's credit arrangements.

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A good credit management system will depend on a good computer system. Under a competitive environment a computer system will need the ability to allow for credit information input from other energy providers and reporting capability to easily identify those customers who are skipping from provider to provider to avoid bad credit. There must also be a system to collect and reimburse bad debts to other utilities for transferring customers.

If electricity is a commodity obtained in a competitive market, it is not unreasonable to expect all energy providers to minimize bad debt. There should be a mechanism established whereby energy providers, not just the Affected Utilities providing standard offer services, work with bad debt customers to determine whether the cause of non-payment is related to a problem with the provider, or whether the customer needs a lifeline rate. If not, the energy provider should be able to notify the distribution company that the customer is in arrears and the energy provider will no longer be serving that customer. At this point, the distribution company will have to determine if the customer can afford standard offer services or not. The main concern is that consistent procedures be developed to eliminate a bad debt burden on the distribution company.

Another dilemma concerning credit management is service termination. The Rules do not specify standards concerning this area, yet considering the implications for some low-income customers, standards need to be developed. New energy providers will probably not have the ability to physically terminate service. The Rules need to determine if the distribution company will be the only company to terminate physical connection. If a new energy provider terminates its service contract, the end user will have the option of choosing another retailer or taking standard offer services depending on the standards established for changing service providers.

2. Billing Corrections

The issue with billing corrections also relates to meter reading issues. Again, this is mostly a coordination issue between the different service providers. The more companies that are involved with customer usage and billing services, the more difficult it will be for correcting a problem. Another concern is who is responsible for determining that a correction is required. Sometimes it will be the customer, but energy providers need to have standards for correct meter readings and review of customer bills.

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3. Customer Deposits

The current Commission rules and regulations support deposits and cost of ownership related to regulated, protected customers. When the market is open to competition and a regulated utility's service territory is no longer protected, these rules are not relevant. Customers will be able to switch energy and other service providers. A new mechanism will need to be put in place so that the company installing the equipment will earn a fair return either through energy charges or a contract. TEP is currently holding millions of dollars that are refundable deposits for line extensions and subdivision contracts. A portion of the contract is refunded when a meter is set and TEP starts receiving revenue for its services. After competition starts, there is no guarantee that TEP will be the service provider and therefore earn its rate of return on the capital installed. Customers may have to have a contract signed in order to get a new installation completed if recovery can not be guaranteed through a service charge.